Annexes

The following seventeen annexes provide additional information to the material presented in the main body of this report. Annexes A through I discuss methodologies for individual source categories in greater detail than was presented in the main body of the report and include explicit activity data and emission factor tables. Annex J lists the Global Warming Potential (GWP) values used in this report as provided in IPCC (1996). Annexes K and J summarize U.S. emissions of ozone depleting substances (e.g., CFCs and HCFCs) and sulfur dioxide (SO_2), respectively. Annex M provides a complete list of emission sources assessed in this report. Annexes N and O present U.S. greenhouse gas emission estimates in the reporting format recommended in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) and the IPCC reference approach for estimating CO_2 emissions from fossil fuel combustion, respectively.

Preliminary greenhouse gas emission estimates for 1997 are provided in Annex P, which will be revised in future reports. Finally, Annex Q addresses the criteria for the inclusion of an emission source category and some of the sources which meet the criteria but are nonetheless excluded from U.S. estimates.

List of Annexes

Annex A

Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion

Carbon dioxide (CO_2) emissions from fossil fuel combustion were estimated using a "bottom-up" methodology characterized by six steps. These steps are described below. Methodological and data changes from previous inventories are outlined at the end of this discussion.

Step 1: Determine Energy Consumption by Fuel Type and End-Use Sector

The bottom-up methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the Intergovernmental Panel on Climate Change (IPCC) for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). Basic consumption data are presented in Columns 2-8 of Table A-1 through Table A-7, with totals by fuel type in Column 8 and totals by end-use sector in the last rows. Fuel consumption data for the bottom-up approach were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy. The EIA data were collected through surveys at the point of delivery or use; therefore, they reflect the reported consumption of fuel by end-use sector and fuel type. Individual data elements were supplied by a variety of sources within EIA. Most information was taken from published reports, although some data were drawn from unpublished energy studies and databases maintained by EIA.

Energy consumption data were aggregated by end-use sector (i.e., residential, commercial, industrial, transportation, electric utilities, and U.S. territories), primary fuel type (e.g., coal, natural gas, and petroleum), and secondary fuel type (e.g., motor gasoline, distillate fuel, etc.). The 1996 total energy consumption across all sectors, including territories, and energy types was 79,419 trillion Btu, as indicated in the last entry of Column 8 in Table A-1. This total includes fuel used for non-fuel purposes and fuel consumed as international bunkers, both of which are deducted in later steps.

There are two modifications made in this report that may cause consumption information herein to differ from figures given in the cited literature. These are the consideration of synthetic natural gas production and ethanol added to motor gasoline.

First, a portion of industrial coal accounted for in EIA combustion figures is actually used to make "synthetic natural gas" via coal gasification. The energy in this gas enters the natural gas stream, and is accounted for in natural gas consumption statistics. Because this energy is already accounted for as natural gas, it is deducted from industrial coal consumption to avoid double counting. This makes the figure for other industrial coal consumption in this report slightly lower than most EIA sources.

Second, ethanol has been added to the motor gasoline stream for several years, but prior to 1993 this addition was not captured in EIA motor gasoline statistics. Starting in 1993, ethanol was included in gasoline statistics. However, because ethanol is a biofuel, which is assumed to result in no net CO_2 emissions, the amount of ethanol added is subtracted from total gasoline consumption. Thus, motor gasoline consumption statistics given in this report may be slightly lower than in EIA sources.

There are also three basic differences between the consumption figures presented in Table A-1 and those recommended in the IPCC emission inventory methodology.

First, consumption data in the U.S. inventory are presented using higher heating values (HHV)[1] rather than the lower heating values (LHV)[2] reflected in the IPCC emission inventory methodology. This convention is followed because data obtained from EIA are based on HHV.

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[1] Also referred to as Gross Calorific Values (GCV).
[2] Also referred to as Net Calorific Values (NCV).

Second, while EIA's energy use data for the United States includes only the 50 U.S. states and the District of Columbia, the data reported to the Framework Convention on Climate Change are to include energy consumption within territories. Therefore, consumption estimates for U.S. territories were added to domestic consumption of fossil fuels. Energy consumption data from U.S. territories are presented in Column 7 of Table A-1. It is reported separately from domestic sectoral consumption, because it is collected separately by EIA with no sectoral disaggregation.

Third, the domestic sectoral consumption figures in Table A-1 include bunker fuels and non-fuel uses of energy. The IPCC recommends that countries estimate emissions from bunker fuels separately and exclude these emissions from national totals, so bunker fuel emissions have been estimated in Table A-8 and deducted from national estimates (see Step 4). Similarly, fossil fuels used to produce non-energy products that store carbon rather than release it to the atmosphere are provided in Table A-9 and deducted from national emission estimates (see Step 3).

Step 2: Determine the Carbon Content of All Fuels

The carbon content of combusted fossil fuels was estimated by multiplying energy consumption (Columns 2 through 8 of Table A-1) by fuel specific carbon content coefficients (Table A-10 and Table A-11) that reflected the amount of carbon per unit of energy inherent in each fuel. The resulting carbon contents are sometimes referred to as potential emissions, or the maximum amount of carbon that could potentially be released to the atmosphere if all carbon in the fuels were converted to CO_2. The carbon content coefficients used in the U.S. inventory were derived by EIA from detailed fuel information and are similar to the carbon content coefficients contained in the IPCC's default methodology (IPCC/UNEP/OECD/IEA 1997), with modifications reflecting fuel qualities specific to the United States.

Step 3: Adjust for the amount of Carbon Stored in Products

Depending on the end-use, non-fuel uses of fossil fuels can result in long term storage of some or all of the carbon contained in the fuel. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon contained in the petroleum feedstock for extended periods of time. Other non-fuel products, such as lubricants or plastics also store carbon, but can lose or emit some of this carbon when they are used and/or burned as waste.

The amount of carbon sequestered or stored by non-fuel uses of fossil fuel products was based upon data that addressed the ultimate fate of various energy products, with all non-fuel use attributed to the industrial, transportation, and territories end-use sectors. This non-fuel consumption is presented in Table A-9. Non-fuel consumption was then multiplied by fuel specific carbon content coefficients (Table A-10 and Table A-11) to obtain the carbon content of the fuel, or the maximum amount of carbon that could be sequestered if all the carbon in the fuel were stored in non-fuel products (Columns 5 and 6 of Table A-9). This carbon content was then multiplied by the fraction of carbon assumed to actually have been sequestered in products (Column 7 of Table A-9), resulting in the final estimates of carbon stored by sector and fuel type, which are presented in Columns 8 through 10 of Table A-3. The portions of carbon sequestered were based on EIA data.

Step 4: Subtract Carbon from Bunker Fuels.

Emissions from international transport activities, or bunker fuel consumption, were not included in national totals. There is currently disagreement internationally as to which countries are responsible for these emissions, and until this issue is resolved, countries are asked to report these emissions separately. However, EIA data includes bunker fuels—primarily residual oil—as part of fuel consumption by the transportation end-use sector. To compensate for this inclusion, bunker fuel emissions were calculated separately (Table A-8) and the carbon content of these fuels was subtracted from the transportation end-use sector. The calculations of bunker fuel emissions followed the same procedures used for other fuel emissions (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized).

Step 5: Account for Carbon that Does Not Oxidize During Combustion

Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted to the atmosphere. Rather, it remains behind as soot, particulate matter, or other by-products of inefficient combustion. The estimated fraction of carbon not oxidized in U.S. energy conversion processes due to inefficiencies during combustion ranges from 0.5 percent for natural gas to 1 percent for petroleum and coal. Except for coal these assumptions are consistent with the default values recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997). In the U.S. unoxidized carbon from coal combustion was estimated to be no more than one percent (Bechtel 1993). Table A-10 presents fractions oxidized by fuel type, which are multiplied by the net carbon content of the combusted energy to give final emissions estimates.

Step 6: Summarize Emission Estimates

Actual CO_2 emissions in the United States were summarized by major fuel (i.e., coal, petroleum, natural gas, geothermal) and consuming sector (i.e., residential, commercial, industrial, transportation, electric utilities, and territories). Adjustments for bunker fuels and carbon sequestered in products were made. Emission estimates are expressed in terms of million metric tons of carbon equivalents (MMTCE).

To determine total emissions by final end-use sector, emissions from electric utilities were distributed over the five end-use sectors according to their share of electricity consumed (see Table A-12).

Differences with Previous Years' Inventories

Two minor changes were made to the estimates of CO_2 emissions from energy consumption in this year's report. The first change concerns how emissions from unmetered natural gas consumption were handled. The second change pertains to accounting for non-fuel uses of fossil fuels in U.S. territories.

Previous inventories included calculations of emissions from unmetered natural gas consumption. Previously, the EIA provided this consumption data, which was calculated as the difference between reported gas production and reported consumption. For many years, the reported amount of gas produced was greater than the amount of gas consumed. EIA assumed that this difference was due to leakage and measurement errors and unmetered consumption. However, during the past two years, the reported amount of gas consumed was higher than the quantity of gas reported to have been produced. This occurrence casts doubt on what composes this difference. Therefore, this year calculations of emissions from unmetered natural gas consumption were not included in the emission estimates.

This year's estimates account for the non-fuel use in U.S. territories. Previous inventories overlooked this small source (0.17 MMTCE in 1996) of carbon sequestration.

Table A-1: 1996 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu)							Emissions (MMTCE) including Adjustments* and Fraction Oxidized						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Utility**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Utility**	**Terr.**	**Total**
Residential Coal	53.7						53.7	1.4						1.4
Commercial Coal		81.0					81.0		2.1					2.1
Industrial Coking Coal			849.7				849.7			20.9				20.9
Industrial Other Coal			1,489.3				1,489.3			38.5				38.5
Coke Imports			(0.3)				(0.3)			(0.0)				(0.0)
Transportation Coal				0.0			0.0				0.0			0.0
Utility Coal					18,086.4		18,086.4					460.9		460.9
US Territory Coal (bit)						10.3	10.3						0.255	0.3
Total Coal	53.7	81.0	2,338.7	0.0	18,086.4	10.3	20,570.0	1.4	2.1	59.4	0.0	460.9	0.3	524.0
Natural Gas	5,375.8	3,289.9	10,311.3	730.6	2,800.8	NA	22,508.4	77.4	47.4	143.0	10.5	40.3	NA	318.6
Asphalt & Road Oil	0.0	0.0	1,175.9	0.0	0.0		1,175.9	0.0	0.0	(0.0)	0.0	0.0	0.000	(0.0)
Aviation Gasoline	0.0	0.0	0.0	37.4	0.0		37.4	0.0	0.0	0.0	0.7	0.0	0.000	0.7
Distillate Fuel Oil	937.5	493.7	1,166.3	4,468.0	109.0	130.7	7,305.2	18.5	9.8	23.0	86.1	2.2	2.581	142.1
Jet Fuel	0.0	0.0	0.0	3,274.2	0.0	79.1	3,353.4	0.0	0.0	0.0	56.7	0.0	1.514	58.2
Kerosene	82.1	24.6	21.4	0.0	0.0		128.1	1.6	0.5	0.4	0.0	0.0	0.000	2.5
LPG	422.0	74.5	2,130.4	34.3	0.0	5.6	2,666.7	7.1	1.3	13.0	0.6	0.0	0.094	22.0
Lubricants	0.0	0.0	172.5	163.0	0.0	1.3	336.8	0.0	0.0	1.7	1.6	0.0	0.013	3.4
Motor Gasoline	0.0	26.2	199.8	14,879.2	0.0	93.7	15,198.9	0.0	0.5	3.8	285.5	0.0	1.783	291.6
Residual Fuel	0.0	156.8	376.0	813.0	605.9	151.7	2,103.4	0.0	3.3	8.0	3.1	12.9	3.227	30.6
Other Petroleum						76.7	76.7						1.367	1.4
AvGas Blend Components			7.0				7.0			0.1				0.1
Crude Oil			13.7				13.7			0.3				0.3
MoGas Blend Components			0.0				0.0			0.0				0.0
Misc. Products			89.0				89.0			1.8				1.8
Naphtha (<401 deg. F)			479.3				479.3			8.6				8.6
Other Oil (>401 deg. F)			729.6				729.6			14.4				14.4
Pentanes Plus			355.0				355.0			1.8				1.8
Petrochemical Feedstocks			0.0				0.0			(13.7)				(13.7)
Petroleum Coke			816.0		20.5		836.5			19.6		0.6		20.2
Still Gas			1,437.1				1,437.1			24.9				24.9
Special Naphtha			74.5				74.5			1.5				1.5
Unfinished Oils			(112.8)				(112.8)			(2.3)				(2.3)
Waxes			48.7				48.7			1.0				1.0
Other Wax & Misc.			0.0				0.0			(3.4)				(3.4)
Total Petroleum	1,441.6	775.8	9,179.5	23,669.1	735.5	538.8	36,340.2	27.2	15.3	104.6	434.3	15.6	10.580	607.7
Geothermal					0.018		0.018					0.0369		0.0369
TOTAL (All Fuels)	6,871.0	4,146.7	21,829.5	24,399.7	21,622.7	549.1	79,418.7	106.0	64.8	307.0	444.8	516.9	10.835	1,450.3

*Adjustments include: international bunker fuel consumption (see Table A-8) and carbon stored in products (see Table A-9)
NA (Not Available)

Table A-2: 1995 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu)							Emissions (MMTCE) including Adjustments* and Fraction Oxidized						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Utility**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Utility**	**Terr.**	**Total**
Residential Coal	53.7						53.7	1.4						1.4
Commercial Coal		81.0					81.0		2.1					2.1
Industrial Coking Coal			884.7				884.7			21.8				21.8
Industrial Other Coal			1,530.7				1,530.7			39.6				39.6
Coke Imports			26.4				26.4			0.7				0.7
Transportation Coal				0.0			0.0				0.0			0.0
Utility Coal					16,978.9		16,978.9					432.7		432.7
US Territory Coal (bit)						10.2	10.2						0.255	0.3
Total Coal	53.7	81.0	2,441.9	0.0	16,978.9	10.2	19,565.7	1.4	2.1	62.1	0.0	432.7	0.3	498.5
Natural Gas	4,981.3	3,185.2	10,064.3	722.0	3,276.4	NA	22,229.3	71.7	45.9	139.7	10.4	47.2	NA	314.8
Asphalt & Road Oil	0.0	0.0	1,178.2	0.0	0.0		1,178.2	0.0	0.0	0.0	0.0	0.0	0.000	0.0
Aviation Gasoline	0.0	0.0	0.0	39.6	0.0		39.6	0.0	0.0	0.0	0.7	0.0	0.000	0.7
Distillate Fuel Oil	893.1	470.3	1,118.7	4,244.4	90.7	135.5	6,952.5	17.6	9.3	22.1	81.8	1.8	2.675	135.3
Jet Fuel	0.0	0.0	0.0	3,132.2	0.0	81.6	3,213.8	0.0	0.0	0.0	54.2	0.0	1.562	55.8
Kerosene	71.7	21.5	18.7	0.0	0.0		111.8	1.4	0.4	0.4	0.0	0.0	0.000	2.2
LPG	398.3	70.3	2,010.8	32.4	0.0	5.6	2,517.3	6.7	1.2	12.5	0.5	0.0	0.095	21.0
Lubricants	0.0	0.0	177.8	167.9	0.0	1.4	347.1	0.0	0.0	1.8	1.7	0.0	0.014	3.5
Motor Gasoline	0.0	25.8	196.7	14,586.4	0.0	97.9	14,906.8	0.0	0.5	3.8	279.9	0.0	1.863	286.0
Residual Fuel	0.0	168.9	371.5	870.0	544.4	156.2	2,110.9	0.0	3.6	7.9	2.9	11.6	3.323	29.3
Other Petroleum						79.3	79.3						1.414	1.4
AvGas Blend Components			5.3				5.3			0.1				0.1
Crude Oil			14.5				14.5			0.3				0.3
MoGas Blend Components			0.0				0.0			0.0				0.0
Misc. Products			97.1				97.1			1.9				1.9
Naphtha (<401 deg. F)			373.0				373.0			6.7				6.7
Other Oil (>401 deg. F)			801.0				801.0			15.8				15.8
Pentanes Plus			337.9				337.9			1.7				1.7
Petrochemical Feedstocks			0.0				0.0			(12.9)				(12.9)
Petroleum Coke			779.0		22.9		802.0			18.9		0.6		19.5
Still Gas			1,417.5				1,417.5			24.6				24.6
Special Naphtha			70.8				70.8			1.4				1.4
Unfinished Oils			(320.9)				(320.9)			(6.4)				(6.4)
Waxes			40.6				40.6			0.8				0.8
Other Wax & Misc.			0.0				0.0			(3.3)				(3.3)
Total Petroleum	1,363.0	756.8	8,688.1	23,072.9	658.0	557.5	35,096.2	25.7	15.0	97.9	421.7	14.0	10.946	585.3
Geothermal					0.016		0.016					0.0328		0.0328
TOTAL (All Fuels)	6,398.0	4,023.0	21,194.3	23,794.8	20,913.3	567.7	76,891.1	98.8	62.9	299.7	432.1	493.9	11.201	1,398.7

*Adjustments include: international bunker fuel consumption (see Table A-8) and carbon stored in products (see Table A-9)
NA (Not Available)

Table A-3: 1994 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu)							Emissions (MMTCE) including Adjustments* and Fraction Oxidized						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Utility**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Utility**	**Terr.**	**Total**
Residential Coal	55.5						55.5	1.4						1.4
Commercial Coal		83.5					83.5		2.1					2.1
Industrial Coking Coal			850.6				850.6			21.0				21.0
Industrial Other Coal			1,589.4				1,589.4			41.1				41.1
Coke Imports			23.6				23.6			0.7				0.7
Transportation Coal				0.0			0.0				0.0			0.0
Utility Coal					16,895.2		16,895.2					430.2		430.2
US Territory Coal (bit)						10.2	10.2						0.255	0.3
Total Coal	55.5	83.5	2,463.7	0.0	16,895.2	10.2	19,508.1	1.4	2.1	62.7	0.0	430.2	0.3	496.7
Natural Gas	4,988.3	2,980.8	9,609.3	705.2	3,052.9	NA	21,336.5	71.8	42.9	133.3	10.2	44.0	NA	302.1
Asphalt & Road Oil	0.0	0.0	1,172.9	0.0	0.0		1,172.9	0.0	0.0	(0.0)	0.0	0.0	0.000	(0.0)
Aviation Gasoline	0.0	0.0	0.0	38.1	0.0		38.1	0.0	0.0	0.0	0.7	0.0	0.000	0.7
Distillate Fuel Oil	880.0	464.3	1,108.8	4,175.0	95.2	101.3	6,824.6	17.4	9.2	21.9	80.4	1.9	2.001	132.7
Jet Fuel	0.0	0.0	0.0	3,154.5	0.0	80.7	3,235.2	0.0	0.0	0.0	54.9	0.0	1.546	56.4
Kerosene	64.9	19.5	16.9	0.0	0.0		101.3	1.3	0.4	0.3	0.0	0.0	0.000	2.0
LPG	395.5	69.8	1,996.5	32.2	0.0	9.2	2,503.1	6.7	1.2	12.8	0.5	0.0	0.156	21.3
Lubricants	0.0	0.0	180.9	170.8	0.0	2.1	353.8	0.0	0.0	1.8	1.7	0.0	0.021	3.5
Motor Gasoline	0.0	25.2	191.9	14,214.1	0.0	131.4	14,562.7	0.0	0.5	3.7	273.7	0.0	2.500	280.4
Residual Fuel	0.0	174.6	417.6	896.0	846.6	171.1	2,505.9	0.0	3.7	8.9	4.6	18.0	3.641	38.8
Other Petroleum						72.6	72.6						1.294	1.3
AvGas Blend Components			6.1				6.1			0.1				0.1
Crude Oil			18.7				18.7			0.4				0.4
MoGas Blend Components			0.0				0.0			0.0				0.0
Misc. Products			105.9				105.9			2.1				2.1
Naphtha (<401 deg. F)			398.3				398.3			7.2				7.2
Other Oil (>401 deg. F)			838.6				838.6			16.6				16.6
Pentanes Plus			338.7				338.7			2.4				2.4
Petrochemical Feedstocks			0.0				0.0			(13.6)				(13.6)
Petroleum Coke			793.0		26.3		819.4			19.4		0.7		20.1
Still Gas			1,439.4				1,439.4			25.0				25.0
Special Naphtha			81.1				81.1			1.6				1.6
Unfinished Oils			(279.2)				(279.2)			(5.6)				(5.6)
Waxes			40.6				40.6			0.8				0.8
Other Wax & Misc.			0.0				0.0			(3.5)				(3.5)
Total Petroleum	1,340.4	753.3	8,866.8	22,680.7	968.2	568.5	35,177.9	25.3	14.9	102.2	416.6	20.6	11.159	590.7
Geothermal					0.024		0.024					0.0492		0.0492
TOTAL (All Fuels)	6,384.2	3,817.6	20,939.8	23,385.9	20,916.2	578.7	76,022.4	98.6	60.0	298.1	426.7	494.8	11.414	1,389.6

*Adjustments include: international bunker fuel consumption (see Table A-8) and carbon stored in products (see Table A-9)
NA (Not Available)

Table A-4: 1993 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu)							Emissions (MMTCE) including Adjustments* and Fraction Oxidized						
Fuel Type	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total
Residential Coal	56.6						56.6	1.5						1.5
Commercial Coal		85.5					85.5		2.2					2.2
Industrial Coking Coal			839.5				839.5			20.7				20.7
Industrial Other Coal			1,588.0				1,588.0			41.1				41.1
Coke Imports			17.3				17.3			0.5				0.5
Transportation Coal				0.0			0.0				0.0			0.0
Utility Coal					16,841.1		16,841.1					428.7		428.7
US Territory Coal (bit)						8.1	8.1						0.201	0.2
Total Coal	56.6	85.5	2,444.8	0.0	16,841.1	8.1	19,436.1	1.5	2.2	62.2	0.0	428.7	0.2	494.7
Natural Gas	5,097.5	2,995.8	9,387.4	643.1	2,744.1	NA	20,867.9	73.4	43.1	131.0	9.3	39.5	NA	296.3
Asphalt & Road Oil	0.0	0.0	1,149.0	0.0	0.0		1,149.0	0.0	0.0	0.0	0.0	0.0	0.000	0.0
Aviation Gasoline	0.0	0.0	0.0	38.4	0.0		38.4	0.0	0.0	0.0	0.7	0.0	0.000	0.7
Distillate Fuel Oil	912.9	463.9	1,099.7	3,912.9	76.7	92.3	6,558.3	18.0	9.2	21.7	75.2	1.5	1.823	127.5
Jet Fuel	0.0	0.0	0.0	3,028.0	0.0	71.4	3,099.4	0.0	0.0	0.0	52.7	0.0	1.369	54.1
Kerosene	75.6	14.0	13.1	0.0	0.0		102.7	1.5	0.3	0.3	0.0	0.0	0.000	2.0
LPG	398.6	70.3	1,794.4	18.9	0.0	12.8	2,295.1	6.7	1.2	12.0	0.3	0.0	0.217	20.4
Lubricants	0.0	0.0	173.1	163.5	0.0	0.2	336.7	0.0	0.0	1.7	1.6	0.0	0.002	3.4
Motor Gasoline	0.0	29.6	179.4	14,000.5	0.0	115.9	14,325.5	0.0	0.6	3.5	269.3	0.0	2.206	275.5
Residual Fuel	0.0	175.0	451.8	913.4	938.6	153.6	2,632.4	0.0	3.7	9.6	4.2	20.0	3.269	40.7
Other Petroleum						83.2	83.2						1.482	1.5
AvGas Blend Components			0.1				0.1			0.0				0.0
Crude Oil			21.2				21.2			0.4				0.4
MoGas Blend Components			0.0				0.0			0.0				0.0
Misc. Products			94.7				94.7			1.9				1.9
Naphtha (<401 deg. F)			350.6				350.6			6.3				6.3
Other Oil (>401 deg. F)			844.1				844.1			16.7				16.7
Pentanes Plus			332.3				332.3			2.0				2.0
Petrochemical Feedstocks			0.0				0.0			(13.1)				(13.1)
Petroleum Coke			767.3		36.8		804.1			18.9		1.0		19.9
Still Gas			1,430.2				1,430.2			24.8				24.8
Special Naphtha			104.6				104.6			2.1				2.1
Unfinished Oils			(396.0)				(396.0)			(7.9)				(7.9)
Waxes			40.0				40.0			0.8				0.8
Other Wax & Misc.			0.0				0.0			(3.3)				(3.3)
Total Petroleum	1,387.0	752.8	8,449.6	22,075.5	1,052.0	529.5	34,246.5	26.2	14.9	98.3	404.1	22.5	10.368	576.4
Geothermal					0.026		0.026					0.0533		0.0533
TOTAL (All Fuels)	6,541.1	3,834.2	20,281.8	22,718.6	20,637.3	537.5	74,550.5	101.0	60.2	291.5	413.4	490.7	10.569	1,367.5

*Adjustments include: international bunker fuel consumption (see Table A-8) and carbon stored in products (see Table A-9)

NA (Not Available)

Table A-5: 1992 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu)							Emissions (MMTCE) including Adjustments* and Fraction Oxidized						
Fuel Type	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total
Residential Coal	56.7						56.7	1.5						1.5
Commercial Coal		85.7					85.7		2.2					2.2
Industrial Coking Coal			867.4				867.4			21.2				21.2
Industrial Other Coal			1,573.1				1,573.1			40.7				40.7
Coke Imports			27.2				27.2			0.7				0.7
Transportation Coal				0.0			0.0				0.0			0.0
Utility Coal					16,192.0		16,192.0					411.8		411.8
US Territory Coal (bit)						8.8	8.8						0.220	0.2
Total Coal	56.7	85.7	2,467.7	0.0	16,192.0	8.8	18,810.9	1.5	2.2	62.6	0.0	411.8	0.2	478.3
Natural Gas	4,821.1	2,884.2	8,996.4	608.4	2,828.5	NA	20,138.6	69.4	41.5	125.8	8.8	40.7	NA	286.2
Asphalt & Road Oil	0.0	0.0	1,102.2	0.0	0.0		1,102.2	0.0	0.0	(0.0)	0.0	0.0	0.000	(0.0)
Aviation Gasoline	0.0	0.0	0.0	41.1	0.0		41.1	0.0	0.0	0.0	0.8	0.0	0.000	0.8
Distillate Fuel Oil	864.9	464.0	1,144.5	3,810.2	67.3	78.7	6,429.6	17.1	9.2	22.6	73.4	1.3	1.554	125.2
Jet Fuel	0.0	0.0	0.0	3,001.3	0.0	65.8	3,067.1	0.0	0.0	0.0	52.3	0.0	1.264	53.5
Kerosene	65.0	11.1	9.8	0.0	0.0		85.9	1.3	0.2	0.2	0.0	0.0	0.000	1.7
LPG	382.5	67.5	1,859.8	18.4	0.0	11.8	2,340.0	6.4	1.1	12.6	0.3	0.0	0.199	20.6
Lubricants	0.0	0.0	170.0	160.5	0.0	0.0	330.5	0.0	0.0	1.7	1.6	0.0	0.000	3.3
Motor Gasoline	0.0	79.5	194.3	13,698.8	0.0	114.4	14,087.0	0.0	1.5	3.7	263.4	0.0	2.176	270.8
Residual Fuel	0.0	191.2	391.3	1,082.0	835.6	154.5	2,654.6	0.0	4.1	8.3	5.5	17.8	3.288	39.0
Other Petroleum						61.4	61.4						1.095	1.1
AvGas Blend Components			0.2				0.2			0.0				0.0
Crude Oil			27.4				27.4			0.5				0.5
MoGas Blend Components			75.7				75.7			1.5				1.5
Misc. Products			100.1				100.1			2.0				2.0
Naphtha (<401 deg. F)			377.3				377.3			6.8				6.8
Other Oil (>401 deg. F)			814.9				814.9			16.1				16.1
Pentanes Plus			322.7				322.7			4.9				4.9
Petrochemical Feedstocks			0.0				0.0			(13.1)				(13.1)
Petroleum Coke			813.1		30.1		843.2			19.0		0.8		19.9
Still Gas			1,447.6				1,447.6			25.1				25.1
Special Naphtha			104.6				104.6			2.1				2.1
Unfinished Oils			(355.0)				(355.0)			(7.1)				(7.1)
Waxes			37.3				37.3			0.7				0.7
Other Wax & Misc.			0.0				0.0			(3.3)				(3.3)
Total Petroleum	1,312.4	813.3	8,637.7	21,812.3	933.0	486.6	33,995.3	24.8	16.1	104.3	397.3	19.9	9.575	572.0
Geothermal					0.028		0.028					0.0574		0.0574
TOTAL (All Fuels)	6,190.2	3,783.2	20,101.8	22,420.7	19,953.5	495.5	72,944.8	95.7	59.9	292.6	406.1	472.5	9.795	1,336.6

*Adjustments include: international bunker fuel consumption (see Table A-8) and carbon stored in products (see Table A-9)
NA (Not Available)

Table A-6: 1991 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu)							Emissions (MMTCE) including Adjustments* and Fraction Oxidized						
Fuel Type	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total
Residential Coal	56.3						56.3	1.4						1.4
Commercial Coal		84.5					84.5		2.2					2.2
Industrial Coking Coal			907.3				907.3			22.6				22.6
Industrial Other Coal			1,629.2				1,629.2			42.0				42.0
Coke Imports			8.9				8.9			0.2				0.2
Transportation Coal				0.0			0.0				0.0			0.0
Utility Coal					16,012.4		16,012.4					407.2		407.2
US Territory Coal (bit)						7.0	7.0						0.175	0.2
Total Coal	56.3	84.5	2,545.4	0.0	16,012.4	7.0	18,705.6	1.4	2.2	64.8	0.0	407.2	0.2	475.8
Natural Gas	4,685.0	2,807.7	8,637.2	621.5	2,853.6	NA	19,605.0	67.5	40.4	120.0	8.9	41.1	NA	277.9
Asphalt & Road Oil	0.0	0.0	1,076.5	0.0	0.0		1,076.5	0.0	0.0	(0.0)	0.0	0.0	0.000	(0.0)
Aviation Gasoline	0.0	0.0	0.0	41.7	0.0		41.7	0.0	0.0	0.0	0.8	0.0	0.000	0.8
Distillate Fuel Oil	831.5	481.6	1,139.2	3,677.6	80.0	72.2	6,282.1	16.4	9.5	22.5	70.5	1.6	1.426	121.9
Jet Fuel	0.0	0.0	0.0	3,025.0	0.0	80.8	3,105.8	0.0	0.0	0.0	53.0	0.0	1.551	54.6
Kerosene	72.3	12.1	11.4	0.0	0.0		95.8	1.4	0.2	0.2	0.0	0.0	0.000	1.9
LPG	389.5	68.7	1,749.3	19.9	0.0	13.7	2,241.1	6.5	1.2	10.9	0.3	0.0	0.233	19.1
Lubricants	0.0	0.0	166.7	157.5	0.0	0.0	324.2	0.0	0.0	1.7	1.6	0.0	0.000	3.2
Motor Gasoline	0.0	85.0	193.3	13,502.6	0.0	117.3	13,898.2	0.0	1.6	3.7	259.5	0.0	2.232	267.0
Residual Fuel	0.0	213.2	335.9	1,031.9	1,076.1	135.0	2,792.1	0.0	4.5	7.1	5.5	22.9	2.872	42.9
Other Petroleum						122.7	122.7						2.186	2.2
AvGas Blend Components			(0.1)				(0.1)			(0.0)				(0.0)
Crude Oil			38.9				38.9			0.8				0.8
MoGas Blend Components			(25.9)				(25.9)			(0.5)				(0.5)
Misc. Products			152.6				152.6			3.1				3.1
Naphtha (<401 deg. F)			298.9				298.9			5.4				5.4
Other Oil (>401 deg. F)			827.3				827.3			16.3				16.3
Pentanes Plus			294.0				294.0			4.7				4.7
Petrochemical Feedstocks			0.0				0.0			(12.2)				(12.2)
Petroleum Coke			700.2		21.7		722.0			17.1		0.6		17.7
Still Gas			1,426.6				1,426.6			24.7				24.7
Special Naphtha			88.0				88.0			1.7				1.7
Unfinished Oils			(450.2)				(450.2)			(9.0)				(9.0)
Waxes			35.1				35.1			0.7				0.7
Other Wax & Misc.			0.0				0.0			(4.4)				(4.4)
Total Petroleum	1,293.3	860.6	8,057.8	21,456.2	1,177.8	541.7	33,387.5	24.4	17.1	94.5	391.1	25.1	10.500	562.6
Geothermal					0.028		0.028					0.0574		0.0574
TOTAL (All Fuels)	6,034.6	3,752.8	19,240.4	22,077.7	20,043.8	548.7	71,698.1	93.3	59.7	279.3	400.1	473.5	10.675	1,316.4

*Adjustments include: international bunker fuel consumption (see Table A-8) and carbon stored in products (see Table A-9)
NA (Not Available)

Table A-7: 1990 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu)							Emissions (MMTCE) including Adjustments* and Fraction Oxidized						
Fuel Type	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total	Res.	Comm.	Ind.	Trans.	Utility	Terr.	Total
Residential Coal	61.9						61.9	1.6						1.6
Commercial Coal		92.9					92.9		2.4					2.4
Industrial Coking Coal			1,041.8				1,041.8			25.9				25.9
Industrial Other Coal			1,646.1				1,646.1			42.4				42.4
Coke Imports			4.8				4.8			0.1				0.1
Transportation Coal				0.0			0.0				0.0			0.0
Utility Coal					16,087.8		16,087.8					409.0		409.0
US Territory Coal (bit)						4.9	4.9						0.122	0.1
Total Coal	61.9	92.9	2,692.7	0.0	16,087.8	4.9	18,940.2	1.6	2.4	68.5	0.0	409.0	0.1	481.6
Natural Gas	4,518.7	2,698.1	8,519.7	682.4	2,861.4	NA	19,280.3	65.1	38.8	118.2	9.8	41.2	NA	273.1
Asphalt & Road Oil	0.0	0.0	1,170.2	0.0	0.0		1,170.2	0.0	0.0	0.0	0.0	0.0	0.000	0.0
Aviation Gasoline	0.0	0.0	0.0	45.0	0.0		45.0	0.0	0.0	0.0	0.8	0.0	0.000	0.8
Distillate Fuel Oil	837.4	487.0	1,180.9	3,830.5	86.3	73.9	6,496.0	16.5	9.6	23.3	73.4	1.7	1.459	126.1
Jet Fuel	0.0	0.0	0.0	3,129.5	0.0	63.5	3,193.0	0.0	0.0	0.0	55.0	0.0	1.220	56.3
Kerosene	63.9	11.8	12.3	0.0	0.0		88.0	1.2	0.2	0.2	0.0	0.0	0.000	1.7
LPG	365.0	64.4	1,607.7	21.8	0.0	14.4	2,073.3	6.1	1.1	10.9	0.4	0.0	0.244	18.7
Lubricants	0.0	0.0	186.3	176.0	0.0	0.8	363.1	0.0	0.0	1.9	1.8	0.0	0.008	3.6
Motor Gasoline	0.0	110.6	184.1	13,577.1	0.0	100.8	13,972.6	0.0	2.1	3.5	260.9	0.0	1.918	268.5
Residual Fuel	0.0	233.1	417.2	1,030.2	1,139.4	121.8	2,941.7	0.0	5.0	8.9	6.7	24.2	2.590	47.4
Other Petroleum						85.2	85.2						1.518	1.5
AvGas Blend Components			0.2				0.2			0.0				0.0
Crude Oil			50.9				50.9			1.0				1.0
MoGas Blend Components			53.7				53.7			1.0				1.0
Misc. Products			137.8				137.8			2.8				2.8
Naphtha (<401 deg. F)			347.8				347.8			6.2				6.2
Other Oil (>401 deg. F)			753.9				753.9			14.9				14.9
Pentanes Plus			250.3				250.3			3.3				3.3
Petrochemical Feedstocks			0.0				0.0			(12.1)				(12.1)
Petroleum Coke			719.9		24.7		744.6			17.3		0.7		18.0
Still Gas			1,473.2				1,473.2			25.5				25.5
Special Naphtha			107.1				107.1			2.1				2.1
Unfinished Oils			(369.0)				(369.0)			(7.4)				(7.4)
Waxes			33.3				33.3			0.7				0.7
Other Wax & Misc.			0.0				0.0			(3.9)				(3.9)
Total Petroleum	1,266.3	906.9	8,317.9	21,810.1	1,250.4	460.3	34,011.9	23.9	18.0	100.2	399.0	26.6	8.957	576.7
Geothermal					0.029		0.029					0.0595		0.0595
TOTAL (All Fuels)	5,846.9	3,697.9	19,530.3	22,492.5	20,199.6	465.2	72,232.4	90.6	59.2	286.8	408.9	476.9	9.079	1,331.4

*Adjustments include: international bunker fuel consumption (see Table A-8) and carbon stored in products (see Table A-9)
NA (Not Available)

Table A-8: 1996 Emissions From International Bunker Fuel Consumption

1	2	3	4	5	6
Fuel Type	Bunker Fuel Consumption (TBtu)	Carbon Content Coefficient (MMTCE/QBtu)[3]	Carbon Content (MMTCE)	Fraction Oxidized	Emissions (MMTCE)
Distillate Fuel	109	19.95	2	0.99	2
Jet Fuel	312	19.33	6	0.99	6
Residual Fuel	665	21.49	14	0.99	14
Total	1,085		22.5		22.3

Table A-9: 1996 Carbon Stored In Products

1	2	3	4	5	6	7	8	9	10
	Non-Fuel Use (TBtu)		Carbon Content Coefficient	Carbon Content (MMTCE)		Fraction Sequestered	Carbon Stored (MMTCE)		
Fuel Type	Ind.	Trans.	(MMTCE/QBtu)	Ind.	Trans.		Ind.	Trans.	Total
Industrial Coking Coal	28		25.53	0.7		0.75	0.532		0.532
Natural Gas	381		14.47	6		1.00	5.520		5.520
Asphalt & Road Oil	1,176		20.62	24		1.00	24.248		24.248
Distillate Fuel Oil	[a]		19.95	0		[a]	[a]		[a]
LPG	1,699		16.99	29		0.80	23.088		23.088
Lubricants	173	163	20.24	3	3	0.50	1.746	1.649	3.395
Residual Fuel	[a]		21.49	0		[a]	[a]		[a]
Naphtha (<401 deg. F)	[b]		18.14	0		[b]	[b]		[b]
Other Oil (>401 deg. F)	[b]		19.95	0		[b]	[b]		[b]
Pentanes Plus	319		18.24	6		0.80	4.651		4.651
Petrochemical Feedstocks	1,204		19.37	21		0.75	13.812		13.812
Petroleum Coke	208		27.85	6		0.50	2.897		2.897
Special Naphtha	75		19.86	1		0.00	0.000		0.000
Other Wax & Misc.	192		19.81	4		1.00	3.417		3.417
Total	5,453	163		101	3		79.9	1.6	81.6

[a] Non-fuel use values of distillate fuel and residual fuel were relatively small and included in the "Other Waxes and Misc." category.
[b] Non-fuel use values of Naphtha (<401 deg. F) and Other Oil (>401 deg. F) are reported in the "Petrochemical Feedstocks" category.

[3] One QBtu is one quadrillion Btu, or 10^{15} Btu. This unit is commonly referred to as a “Quad.”

Table A-10: Key Assumptions for Estimating Carbon Dioxide Emissions

Fuel Type	Carbon Content Coefficient (MMTCE/QBtu)	Fraction Oxidized
Coal		
Residential Coal	[a]	0.99
Commercial Coal	[a]	0.99
Industrial Coking Coal	[a]	0.99
Industrial Other Coal	[a]	0.99
Coke Imports	27.85	0.99
Transportation Coal	NC	0.99
Utility Coal	[a]	0.99
U.S. Territory Coal (bit)	25.14	0.99
Natural Gas	14.47	0.995
Petroleum		
Asphalt & Road Oil	20.62	0.99
Aviation Gasoline	18.87	0.99
Distillate Fuel Oil	19.95	0.99
Jet Fuel	[a]	0.99
Kerosene	19.72	0.99
LPG	[a]	0.99
Lubricants	20.24	0.99
Motor Gasoline	[a]	0.99
Residual Fuel	21.49	0.99
Other Petroleum		
AvGas Blend Components	18.87	0.99
Crude Oil	[a]	0.99
MoGas Blend Components	19.39	0.99
Misc. Products	20.23	0.99
Naphtha (<401 deg. F)	18.14	0.99
Other Oil (>401 deg. F)	19.95	0.99
Pentanes Plus	18.24	0.99
Petrochemical Feedstocks	19.37	0.99
Petroleum Coke	27.85	0.99
Still Gas	17.51	0.99
Special Naphtha	19.86	0.99
Unfinished Oils	20.23	0.99
Waxes	19.81	0.99
Other Wax & Misc.	19.81	0.99
Geothermal	2.05	NA

Sources: Carbon Coefficients and stored carbon from EIA. Combustion efficiency for coal from Bechtel (1993) and for petroleum and natural gas from IPCC (IPCC/UNEP/OECD/IEA 1997, vol. 2).
NA (Not Applicable)
NC (Not Calculated)
[a] These coefficients vary annually due to fluctuations in fuel quality (see Table A-11).

Table A-11: Annually Variable Carbon Content Coefficients by Year (MMTCE/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996
Residential Coal	25.92	26.00	26.13	25.97	25.95	26.00	26.00
Commercial Coal	25.92	26.00	26.13	25.97	25.95	26.00	26.00
Industrial Coking Coal	25.51	25.51	25.51	25.51	25.52	25.53	25.53
Industrial Other Coal	25.58	25.59	25.62	25.61	25.63	25.63	25.63
Utility Coal	25.68	25.69	25.69	25.71	25.72	25.74	25.74
LPG	16.99	16.98	16.99	16.97	17.01	17.00	16.99
Motor Gasoline	19.41	19.41	19.42	19.43	19.45	19.38	19.38
Jet Fuel	19.40	19.40	19.39	19.37	19.35	19.34	19.33
Crude Oil	20.14	20.16	20.20	20.20	20.19	20.21	20.23

Source: EIA

Table A-12: Electricity Consumption by End-Use Sector (Billion Kilowatt-hours)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996
Residential	924	955	936	995	1,008	1,043	1,078
Commercial	839	856	851	886	914	954	985
Industrial	946	947	973	977	1,008	1,013	1,017
Transportation	4	4	4	4	4	4	4
U.S. Territories*	-	-	-	-	-	-	-
Total	2,713	2,762	2,764	2,862	2,934	3,014	3,084

*EIA electric utility fuel consumption data does not include the U.S. territories.
- Not applicable
Source: EIA

Annex B

Methodology for Estimating Emissions of CH_4, N_2O, and Criteria Pollutants from Stationary Sources

Estimates of CH_4 and N_2O Emissions from Stationary Combustion

Methane (CH_4) and nitrous oxide (N_2O) emissions from stationary source fossil fuel combustion were estimated using IPCC emission factors and methods. Estimates were obtained by multiplying emission factors (by sector and fuel type) by fossil fuel and wood consumption data. This “top-down” methodology is characterized by two basic steps, described below. Data are presented in Table B-1 through Table B-9. Changes in the methodology for this source are outlined at the end of this discussion.

Step 1: Determine Energy Consumption by Sector and Fuel Type

Greenhouse gas emissions from stationary combustion activities were grouped into four sectors: industrial, commercial/institutional, residential, and electric utilities. For CH_4 and N_2O, estimates were based upon consumption of coal, gas, oil, and wood. Energy consumption data were obtained from EIA’s Monthly Energy Review (1997), and adjusted to lower heating values assuming a 10 percent reduction for natural gas and a 5 percent reduction for coal and petroleum fuels. Table B-1 provides annual energy consumption data for the years 1990 through 1996.

Step 2: Determine the Amount of CH_4 and N O Emitted

Activity data for each sector and fuel type were multiplied by emission factors to obtain emissions estimates. Emission factors were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). Table B-2 provides emission factors used for each sector and fuel type.

Estimates of NO , CO, and NMVOC Emissions from Stationary Combustion

For criteria pollutants, the major source categories included were those identified in EPA (1997): coal, fuel oil, natural gas, wood, other fuels (including bagasse, liquefied petroleum gases, coke, coke oven gas, and others), and stationary internal combustion (which includes emissions from internal combustion engines not used in transportation). EPA (1997) periodically estimates emissions of NO_x, CO, and NMVOCs by sector and fuel type using a "bottom-up" estimating procedure. In other words, the emissions were calculated either for individual sources (e.g., industrial boilers) or for many sources combined, using basic activity data (e.g., fuel consumption or deliveries, etc.) as indicators of emissions. EPA (1997) projected emissions for years subsequent to their bottom-up estimates. The national activity data used to calculate the individual categories were obtained from various sources. Depending upon the category, these activity data may include fuel consumption or deliveries of fuel, tons of refuse burned, raw material processed, etc. Activity data were used in conjunction with emission factors that relate the quantity of emissions to the activity. Table B-3 through Table B-9 present criteria pollutant emission estimates for 1990 through 1996.

The basic calculation procedure for most source categories presented in EPA (1997) is represented by the following equation:

$$E_{p,s} = A_s \times Ef_{p,s} \times (1 - C_{p,s}/100)$$

where,

E = emissions

p = pollutant

s = source category

A = activity level

EF = emission factor

C = percent control efficiency

The EPA currently derives the overall emission control efficiency of a category from a variety of sources, including published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary combustion as described above is similar to the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

Differences with Previous Years' Inventories

In previous editions of the Inventory, methane emissions from stationary sources were calculated using a different methodology. Rather than using activity data and emission factors, CH_4 emissions were calculated as a ratio of NMVOC emissions. The accuracy of stationary source methane emissions have been improved in this year's inventory with the use of fuel type and end-use specific emission factors in place of the previous NMVOC ratio.

Table B-1: Fuel Consumption by Stationary Sources for Calculating CH_4 and N_2O Emissions (TBtu)

Fuel/End-Use Sector	1990	1991	1992	1993	1994	1995	1996
Coal	18,935.3	18,698.6	18,802.1	19,428.0	19,497.8	19,555.4	20,559.8
Residential	61.9	56.3	56.7	56.6	55.5	53.7	53.7
Commercial/Institutional	92.9	84.5	85.7	85.5	83.5	81.0	81.0
Industry	2,692.7	2,545.4	2,467.7	2,444.8	2,463.7	2,441.9	2,338.7
Utilities	16,087.8	16,012.4	16,192.0	16,841.1	16,895.2	16,978.9	18,086.4
Petroleum	11,741.5	11,389.6	11,696.4	11,641.5	11,928.7	11,465.9	12,132.3
Residential	1,266.3	1,293.3	1,312.4	1,387.0	1,340.4	1,363.0	1,441.6
Commercial/Institutional	906.9	860.6	813.3	752.8	753.3	756.8	775.8
Industry	8,317.9	8,057.8	8,637.7	8,449.6	8,866.8	8,688.1	9,179.5
Utilities	1,250.4	1,177.8	933.0	1,052.0	968.2	658.0	735.5
Natural Gas	18,597.9	18,983.5	19,530.2	20,224.9	20,631.3	21,507.3	21,777.8
Residential	4,518.7	4,685.0	4,821.1	5,097.5	4,988.3	4,981.3	5,375.8
Commercial/Institutional	2,698.1	2,807.7	2,884.2	2,995.8	2,980.8	3,185.2	3,289.9
Industry	8,519.7	8,637.2	8,996.4	9,387.4	9,609.3	10,064.3	10,311.3
Utilities	2,861.4	2,853.6	2,828.5	2,744.1	3,052.9	3,276.4	2,800.8
Wood	2,185.0	2,181.0	2,279.0	2,228.0	2,266.0	2,350.0	2,440
Residential	581.0	613.0	645.0	548.0	537.0	596.0	595.0
Commercial/Institutional	30.0	30.0	30.0	44.0	45.0	45.0	49.0
Industrial	1,562.0	1,528.0	1,593.0	1,625.0	1,673.0	1,698.0	1,784.0
Utilities	12.0	10.0	11.0	11.0	11.0	11.0	12.0

Table B-2: CH_4 and N_2O Emission Factors by Fuel Type and Sector (g/GJ)[4]

Fuel/End-Use Sector	CH_4	N_2O
Coal		
Residential	300	1.4
Commercial/Institutional	10	1.4
Industry	10	1.4
Utilities	1	1.4
Petroleum		
Residential	10	0.6
Commercial/Institutional	10	0.6
Industry	2	0.6
Utilities	3	0.6
Natural Gas		
Residential	5	0.1
Commercial/Institutional	5	0.1
Industry	5	0.1
Utilities	1	0.1
Wood		
Residential	300	4.0
Commercial/Institutional	300	4.0
Industrial	30	4.0
Utilities	30	4.0

[4] GJ (Gigajoule) = 10^9 joules. One joule = 9.486×10^{-4} Btu

Table B-3: 1996 NO_x, NMVOC, and CO Emissions from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	NMVOC	CO
Electric Utilities	5,473	341	41
Coal	5,004	238	28
Fuel Oil	87	10	3
Natural gas	244	40	2
Wood	NA	NA	NA
Internal Combustion	137	53	9
Industrial	2,875	972	188
Coal	543	90	5
Fuel Oil	223	65	11
Natural gas	1,212	316	66
Wood	NA	NA	NA
Other Fuels[a]	113	277	46
Internal Combustion	784	224	60
Commercial/Institutional	366	227	21
Coal	35	14	1
Fuel Oil	93	17	3
Natural gas	212	49	10
Wood	NA	NA	NA
Other Fuels[a]	26	148	8
Residential	804	3,866	724
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	44	3,621	687
Other Fuels[a]	760	244	37
Total	9,518	5,407	975

NA (Not Available)
[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).
[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).
Note: Totals may not sum due to independent rounding.

Table B-4: 1995 NO_x, NMVOC, and CO Emissions from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	NMVOC	CO
Electric Utilities	5,791	40	338
Coal	5,060	26	227
Fuel Oil	87	2	9
Natural gas	510	2	49
Wood	NA	NA	NA
Internal Combustion	134	9	52
Industrial	2,852	187	958
Coal	541	5	88
Fuel Oil	224	11	64
Natural gas	1,201	66	313
Wood	NA	NA	NA
Other Fuels[a]	111	45	270
Internal Combustion	774	59	222
Commercial/Institutional	365	21	211
Coal	35	1	14
Fuel Oil	94	3	17
Natural gas	210	10	49
Wood	NA	NA	NA
Other Fuels[a]	27	8	132
Residential	812	725	3,876
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	44	688	3,628
Other Fuels[a]	768	37	248
Total	9,820	973	5,382

NA (Not Available)
[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).
[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).
Note: Totals may not sum due to independent rounding.

Table B-5: 1994 NO_x, NMVOC, and CO Emissions from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	NMVOC	CO
Electric Utilities	5,955	41	335
Coal	5,112	26	224
Fuel Oil	148	4	13
Natural gas	536	2	48
Wood	NA	NA	NA
Internal Combustion	159	9	50
Industrial	2,854	178	944
Coal	546	7	91
Fuel Oil	219	11	60
Natural gas	1,209	57	306
Wood	NA	NA	NA
Other Fuels[a]	113	45	260
Internal Combustion	767	58	228
Commercial/Institutional	365	21	212
Coal	36	1	13
Fuel Oil	86	3	16
Natural gas	215	10	49
Wood	NA	NA	NA
Other Fuels[a]	28	8	134
Residential	817	657	3,514
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	40	621	3,271
Other Fuels[a]	777	36	243
Total	9,990	897	5,006

NA (Not Available)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).

[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).

Note: Totals may not sum due to independent rounding.

Table B-6: 1993 NO_x, NMVOC, and CO Emissions from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	NMVOC	CO
Electric Utilities	6,033	41	329
Coal	5,210	26	223
Fuel Oil	163	4	15
Natural gas	500	2	45
Wood	NA	NA	NA
Internal Combustion	160	9	46
Industrial	2,858	169	946
Coal	534	5	92
Fuel Oil	222	11	60
Natural gas	1,206	46	292
Wood	NA	NA	NA
Other Fuels[a]	113	46	259
Internal Combustion	782	60	243
Commercial/Institutional	360	22	207
Coal	37	1	14
Fuel Oil	84	3	16
Natural gas	211	10	48
Wood	NA	NA	NA
Other Fuels[a]	28	8	129
Residential	827	670	3,585
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	40	633	3,337
Other Fuels[a]	786	36	248
Total	10,077	901	5,067

NA (Not Available)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).

[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).

Note: Totals may not sum due to independent rounding.

Table B-7: 1992 NO_x, NMVOC, and CO Emissions from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	NMVOC	CO
Electric Utilities	**5,899**	**40**	**318**
Coal	5,060	25	214
Fuel Oil	154	4	14
Natural gas	526	2	47
Wood	NA	NA	NA
Internal Combustion	159	9	43
Industrial	**2,785**	**169**	**866**
Coal	521	7	92
Fuel Oil	222	11	58
Natural gas	1,180	47	272
Wood	NA	NA	NA
Other Fuels[a]	115	45	239
Internal Combustion	748	60	205
Commercial/Institutional	**348**	**20**	**204**
Coal	35	1	13
Fuel Oil	84	3	16
Natural gas	204	9	46
Wood	NA	NA	NA
Other Fuels[a]	25	7	128
Residential	**879**	**782**	**4,194**
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	48	746	3,929
Other Fuels[a]	831	36	265
Total	**9,912**	**1,010**	**5,582**

NA (Not Available)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).

[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).

Note: Totals may not sum due to independent rounding.

Table B-8: 1991 NO_x, NMVOC, and CO Emissions from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	NMVOC	CO
Electric Utilities	**5,913**	**40**	**317**
Coal	5,042	25	212
Fuel Oil	192	5	17
Natural gas	526	2	46
Wood	NA	NA	NA
Internal Combustion	152	9	41
Industrial	**2,702**	**177**	**834**
Coal	517	5	92
Fuel Oil	215	10	54
Natural gas	1,134	54	257
Wood	NA	NA	NA
Other Fuels[a]	117	47	242
Internal Combustion	720	61	189
Commercial/Institutional	**333**	**18**	**196**
Coal	33	1	13
Fuel Oil	80	2	16
Natural gas	191	8	40
Wood	NA	NA	NA
Other Fuels[a]	29	7	128
Residential	**829**	**739**	**3,964**
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	45	704	3,710
Other Fuels[a]	784	35	254
Total	**9,777**	**975**	**5,312**

NA (Not Available)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).

[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).

Note: Totals may not sum due to independent rounding.

Table B-9: 1990 NO_x, NMVOC, and CO Emissions from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	NMVOC	CO
Electric Utilities	**6,043**	**43**	**329**
Coal	5,117	25	213
Fuel Oil	200	5	18
Natural gas	513	2	46
Wood	NA	NA	NA
Internal Combustion	213	11	52
Industrial	**2,753**	**165**	**797**
Coal	530	7	95
Fuel Oil	240	11	67
Natural gas	1,072	52	205
Wood	NA	NA	NA
Other Fuels[a]	119	46	253
Internal Combustion	792	49	177
Commercial/Institutional	**336**	**18**	**205**
Coal	36	1	13
Fuel Oil	88	3	16
Natural gas	181	7	40
Wood	NA	NA	NA
Other Fuels[a]	31	8	136
Residential	**749**	**686**	**3,667**
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	42	651	3,429
Other Fuels[a]	707	35	238
Total	**9,881**	**912**	**4,998**

NA (Not Available)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).

[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).

Note: Totals may not sum due to independent rounding.

Annex C

Methodology for Estimating Emissions of CH_4, N_2O, and Criteria Pollutants from Mobile Sources

Estimates of CH_4 and N_2O Emissions from Mobile Combustion

Greenhouse gas emissions from mobile sources are reported by transport mode (e.g., road, rail, air, and water), vehicle type, and fuel. EPA does not systematically track emissions of CH_4 and N_2O; therefore, estimates of these gases were developed using a methodology similar to that outlined in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Step 1: Determine Vehicle Miles Traveled or Fuel Consumption by Vehicle Type, Fuel Type, and Model Year

Activity data were obtained from a number of U.S. government agency publications. Depending on the category, these basic activity data included such information as fuel consumption, fuel deliveries, and vehicle miles traveled (VMT). The activity data for highway vehicles included estimates of VMT by vehicle type and model year from EPA (1997a) and the MOBILE5a emissions model (EPA 1997b).

National VMT data for gasoline and diesel highway vehicles are presented in Table C-1 and Table C-2, respectively. Total VMT for each highway category (i.e., gasoline passenger cars, light-duty gasoline trucks, heavy-duty gasoline vehicles, diesel passenger cars, light-duty diesel trucks, heavy-duty diesel vehicles, and motorcycles) were distributed across 25 model years based on the temporally fixed age distribution of VMT by the U.S. vehicle fleet in 1990 (see Table C-3) as specified in MOBILE5a. Activity data for gasoline passenger cars and light-duty trucks in California were developed separately due to the different emission control technologies deployed in that state relative to the rest of the country. Unlike the rest of the United States, beginning in model year 1994, a fraction of the California VMT for gasoline passenger cars and light-duty trucks was attributed to for low emission vehicles (LEVs). LEVs have not yet been widely deployed in other states. Based upon U.S. Department of Transportation statistics for 1994, it was assumed that 8.7 percent of national VMT occurred in California.

Activity data for non-highway vehicles were based on annual fuel consumption statistics by transportation mode and fuel type. Consumption data for distillate and residual fuel oil by ocean-going ships (i.e., marine bunkers), boats, construction equipment, farm equipment, and locomotives were obtained from EIA (1997). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from FAA (1997). Consumption of motor gasoline by boats, construction equipment, farm equipment, and locomotives data were drawn from FHWA (1997). The activity data used for non-highway vehicles are included in Table C-4.

Step 2: Allocate VMT Data to Control Technology Type for Highway Vehicles

For highway sources, VMT by vehicle type for each model year were distributed across various control technologies as shown in Table C-5, Table C-6, Table C-7, Table C-8, and Table C-9. Again, California gasoline-fueled passenger cars and light-duty trucks were treated separately due to that state's distinct mobile source emission standards—including the introduction of LEVs in 1994—compared with the rest of the United States. The categories "Tier 0" and "Tier 1" have been substituted for the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the *Revised 1996 IPCC Guidelines*. Tier 0, Tier 1, and LEV are actually U.S. emission regulations, rather than control technologies; however, each does correspond to particular combinations of control technologies and engine design. Tier 1 and its predecessor Tier 0 both apply to vehicles equipped with three-way catalysts. The introduction of "early three-way catalysts," and "advance three-way catalysts" as described in the *Revised 1996 IPCC Guidelines*, roughly correspond to the introduction of Tier 0 and Tier 1 regulations (EPA 1998).

Step 3: Determine the Amount of CH_4 and N_2O Emitted by Vehicle, Fuel, and Control Technology Type

Emissions of CH_4 from mobile source combustion were calculated by multiplying emission factors in IPCC/UNEP/OECD/IEA (1997) by activity data for each vehicle type as described in Step 1 (see Table C-10 and Table C-11). The CH_4 emission factors for highway sources were derived from EPA's MOBILE5a mobile source emissions model (EPA 1997b). The MOBILE5a model uses information on ambient temperature, diurnal temperature range, altitude, vehicle speeds, national vehicle registration distributions, gasoline volatility, emission control technologies, fuel composition, and the presence or absence of vehicle inspection/maintenance programs in order to produce these factors.

Emissions of N_2O—in contrast to CH_4, CO, NO_x, and NMVOCs—have not been extensively studied and are currently not well characterized. The limited number of studies that have been done on highway vehicle emissions of N_2O have shown that emissions are generally greater from vehicles with catalytic converter systems than those without such controls, and greater from aged than from new catalysts. These systems control tailpipe emissions of NO_x (i.e., NO and NO_2) by catalytically reducing NO_x to N_2. Suboptimal catalyst performance, caused by as yet poorly understood factors, results in incomplete reduction and the conversion of some NO_x to N_2O rather than to N_2. Fortunately, newer vehicles with catalyst and engine designs meeting the more recent Tier 1 and LEV standards have shown reduced emission rates of both NO_x and N_2O.

In order to better characterize the process by which N_2O is formed by catalytic controls and to develop a more accurate national emission estimate, the EPA's Office of Mobile Sources—at its National Vehicle and Fuel Emissions Laboratory (NVFEL)—recently conducted a series of tests in order to measure emission rates of N_2O from used Tier 1 and LEV gasoline-fueled passenger cars and light-duty trucks equipped with catalytic converters. These tests and a review of the literature were used to develop the emission factors for nitrous oxide used in this inventory (EPA 1998). The following references were used in developing the N_2O emission factors for gasoline-fueled highway passenger cars presented in Table C-10:

- *LEVs*. Tests performed at NVFEL (EPA 1998)[5]
- *Tier 1*. Tests performed at NVFEL (EPA 1988)
- *Tier 0*. Smith and Carey (1982), Barton and Simpson (1994), and one car tested at NVFEL (EPA 1998)
- *Oxidation Catalyst*. Smith and Carey (1982), Urban and Garbe (1979)
- *Non-Catalyst*. Prigent and de Soete (1989), Dasch (1992), and Urban and Garbe (1979)

Nitrous oxide emission factors for other types of gasoline-fueled vehicles—light-duty trucks, heavy-duty vehicles, and motorcycles—were estimated by adjusting the factors for gasoline passenger cars, as described above, by their relative fuel economies. This adjustment was performed using the carbon dioxide emission rates in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) as a proxy for fuel economy (see Table C-10). Data from the literature and tests performed at NVFEL support the conclusion that light-duty trucks have higher emission rates than passenger cars. However, the use of fuel-consumption ratios to determine emission factors is considered a temporary measure only, to be replaced as soon as real data are available.

The resulting N_2O emission factors employed for gasoline highway vehicles are lower than the U.S. default values presented in the *Revised 1996 IPCC Guidelines*, but are higher than the European default values, both of which were published before the more recent tests and literature review conducted by the NVFEL. The U.S. defaults in the *Guidelines* were based on three studies that tested a total of five cars using European rather than U.S. test procedures. Nitrous oxide emission factors for diesel highway vehicles were taken from the European default values found in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). There is little data addressing N_2O emissions from U.S. diesel-fueled vehicles, and in general, European countries have had more experience with diesel-fueled vehicles. U.S. default values in the *Revised 1996 IPCC Guidelines* were used for non-highway vehicles.

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5 It was assumed that LEVs would be operated using low-sulfur fuel (i.e., Indolene at 24 ppm sulfur). All other NVFEL tests were performed using a standard commercial fuel (CAAB at 285 ppm sulfur). Emission tests by NVFEL have consistently exhibited higher N_2O emission rates from higher sulfur fuels on Tier 1 and LEV vehicles.

Compared to regulated tailpipe emissions, there is relatively little data available to estimate emission factors for nitrous oxide. Nitrous oxide is not a criteria pollutant, and measurements of it in automobile exhaust have not been routinely collected. Further testing is needed to reduce the uncertainty in nitrous oxide emission factors for all classes of vehicles, using realistic driving regimes, environmental conditions, and fuels.

Estimates of NO_x, CO, and NMVOC Emissions From Mobile Combustion

The emission estimates of NO_x, CO, and NMVOCs for mobile sources were taken directly from the EPA's *National Air Pollutant Emissions Trends, 1900 - 1996* (EPA 1997a). This EPA report provides emission estimates for these gases by sector and fuel type using a "top down" estimating procedure whereby emissions were calculated using basic activity data, such as amount of fuel delivered or miles traveled, as indicators of emissions. Table C-12 through Table C-18 provide complete emissions estimates for 1990 through 1996.

Table C-1: Vehicle Miles Traveled for Gasoline Highway Vehicles (10^9 Miles)

Year	Passenger Cars[a]	Light-Duty Trucks[a]	Heavy-Duty Vehicles	Motorcycles	Passenger Cars (CA)[b]	Light-Duty Trucks (CA)[b]
1990	1362.75	422.09	43.32	9.57	129.86	40.22
1991	1381.11	428.12	43.60	9.20	131.61	40.80
1992	1437.57	431.76	43.39	9.55	136.99	41.14
1993	1462.88	450.30	45.96	9.89	139.40	42.91
1994	1426.55	531.21	49.67	10.25	135.94	50.62
1995	1466.04	545.90	51.04	10.52	139.70	52.02
1996	1492.35	555.84	52.00	10.73	142.21	52.97

[a] Excludes California

[b] California VMT for passenger cars and light-duty trucks was treated separately and estimated as 8.7 percent of national total.

Source: VMT data are the same as those used in EPA (1997a).

Table C-2: Vehicle Miles Traveled for Diesel Highway Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	20.59	3.77	112.20
1991	20.87	3.84	112.91
1992	21.72	3.92	114.95
1993	22.09	4.08	119.61
1994	21.55	4.82	126.99
1995	22.14	4.95	130.50
1996	22.55	5.05	132.95

Source: VMT data are the same as those used in EPA (1997a).

Table C-3: VMT Profile by Vehicle Age (years) and Vehicle/Fuel Type for Highway Vehicles (percent of VMT)

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
1	4.9%	6.3%	2.3%	4.9%	6.3%	3.4%	14.4%
2	7.9%	8.4%	4.7%	7.9%	8.4%	6.7%	16.8%
3	8.3%	8.4%	4.7%	8.3%	8.4%	6.7%	13.5%
4	8.2%	8.4%	4.7%	8.2%	8.4%	6.7%	10.9%
5	8.4%	8.4%	4.7%	8.4%	8.4%	6.7%	8.8%
6	8.1%	6.9%	3.8%	8.1%	6.9%	7.3%	7.0%
7	7.7%	5.9%	3.3%	7.7%	5.9%	6.1%	5.6%
8	5.6%	4.4%	2.1%	5.6%	4.4%	4.0%	4.5%
9	5.0%	3.6%	2.6%	5.0%	3.6%	4.1%	3.6%
10	5.1%	3.1%	2.9%	5.1%	3.1%	5.1%	2.9%
11	5.0%	3.0%	3.4%	5.0%	3.0%	5.3%	2.3%
12	5.4%	5.3%	6.4%	5.4%	5.3%	6.6%	9.7%
13	4.7%	4.7%	5.4%	4.7%	4.7%	5.5%	0%
14	3.7%	4.6%	5.8%	3.7%	4.6%	5.7%	0%
15	2.4%	3.6%	5.1%	2.4%	3.6%	4.5%	0%
16	1.9%	2.8%	3.8%	1.9%	2.8%	1.9%	0%
17	1.4%	1.7%	4.3%	1.4%	1.7%	2.3%	0%
18	1.5%	2.2%	4.1%	1.5%	2.2%	2.8%	0%
19	1.1%	1.7%	3.5%	1.1%	1.7%	2.4%	0%
20	0.8%	1.4%	2.9%	0.8%	1.4%	1.6%	0%
21	0.6%	0.9%	2.1%	0.6%	0.9%	1.1%	0%
22	0.5%	0.8%	2.2%	0.5%	0.8%	0.9%	0%
23	0.4%	0.8%	2.2%	0.4%	0.8%	0.7%	0%
24	0.3%	0.5%	1.4%	0.3%	0.5%	0.5%	0%
25	1.0%	2.5%	11.7%	1.0%	2.5%	1.6%	0%

LDGV (gasoline passenger cars, also referred to as light-duty gas vehicles)
LDGT (light-duty gas trucks)
HDGV (heavy-duty gas vehicles)
LDDV (diesel passenger cars, also referred to as light-duty diesel vehicles)
LDDT (light-duty diesel trucks)
HDDV (heavy-duty diesel vehicles)
MC (motorcycles)

Table C-4: Fuel Consumption for Non-Highway Vehicles by Fuel Type (U.S. Gallons)

Vehicle Type/Year	Residual	Diesel	Jet Fuel	Other
Aircraft[a]				
1990	-	-	12,986,111,661	353,100,000
1991	-	-	11,995,880,426	353,600,000
1992	-	-	12,279,912,686	314,000,000
1993	-	-	12,326,549,428	268,400,000
1994	-	-	12,855,125,825	264,100,000
1995	-	-	13,140,841,990	258,100,000
1996	-	-	13,677,564,463	275,800,000
Marine Bunkers				
1990	4,686,071,250	549,251,000	-	-
1991	5,089,541,250	541,910,000	-	-
1992	5,399,308,500	560,042,500	-	-
1993	4,702,411,500	510,936,250	-	-
1994	4,458,628,500	506,724,750	-	-
1995	4,823,428,500	494,526,250	-	-
1996	4,353,732,750	544,402,000	-	-
Boats[b]				
1990	1,562,023,750	1,647,753,000	-	1,300,400,000
1991	1,696,513,750	1,625,730,000	-	1,709,700,000
1992	1,799,769,500	1,680,127,500	-	1,316,170,000
1993	1,567,470,500	1,532,808,750	-	873,687,000
1994	1,486,209,500	1,520,174,250	-	896,700,000
1995	1,607,809,500	1,483,578,750	-	1,060,394,000
1996	1,451,244,250	1,633,206,000	-	1,060,394,000
Construction Equipment[c]				
1990	-	2,508,300,000	-	1,523,600,000
1991	-	2,447,400,000	-	1,384,900,000
1992	-	2,287,642,000	-	1,492,200,000
1993	-	2,323,183,000	-	1,464,599,000
1994	-	2,437,142,000	-	1,492,152,000
1995	-	2,273,162,000	-	1,499,346,000
1996	-	2,386,973,000	-	1,499,346,000
Farm Equipment				
1990	-	3,164,200,000	-	812,800,000
1991	-	3,144,200,000	-	776,200,000
1992	-	3,274,811,000	-	805,500,000
1993	-	3,077,122,000	-	845,320,000
1994	-	3,062,436,000	-	911,996,000
1995	-	3,093,224,000	-	926,732,000
1996	-	3,225,029,000	-	926,732,000
Locomotives				
1990	25,422	3,210,111,000	-	-
1991	6,845	3,026,292,000	-	-
1992	8,343	3,217,231,000	-	-
1993	4,065	2,906,998,000	-	-
1994	5,956	3,063,441,000	-	-
1995	6,498	3,191,023,000	-	-
1996	6,498	3,266,861,000	-	-

- Not applicable
Sources: FWHA 1997, EIA 1997, and FAA 1997.
[a] Other Fuel = Aviation Gasoline.
[b] Other Fuel = Motor Gasoline
[c] Construction Equipment includes snowmobiles. Other Fuel = Motor Gasoline

Table C-5: Control Technology Assignments for Gasoline Passenger Cars (percentage of VMT)*

Model Years	Uncontrolled	Non-catalyst	Oxidation	Tier 0	Tier 1
≤1972	100%				
1973-1974		100%			
1975		20%	80%		
1976-1977		15%	85%		
1978-1979		10%	90%		
1980		5%	88%	7%	
1981			15%	85%	
1982			14%	86%	
1983			12%	88%	
1984-1993				100%	
1994				60%	40%
1995				20%	80%
1996					100%

* Excluding California VMT

Table C-6: Control Technology Assignments for Gasoline Light-Duty Trucks (percentage of VMT)*

Model Years	Uncontrolled	Non-catalyst	Oxidation	Tier 0	Tier 1
≤1972	100%				
1973-1974		100%			
1975		30%	70%		
1976		20%	80%		
1977-1978		25%	75%		
1979-1980		20%	80%		
1981			95%	5%	
1982			90%	10%	
1983			80%	20%	
1984			70%	30%	
1985			60%	40%	
1986			50%	50%	
1987-1993			5%	95%	
1994				60%	40%
1995				20%	80%
1996					100%

* Excluding California VMT

Table C-7: Control Technology Assignments for California Gasoline Passenger Cars and Light-Duty Trucks (percentage of VMT)

Model Years	Uncontrolled	Non-catalyst	Oxidation	Tier 0	Tier 1	LEV
≤1972	100%					
1973-1974		100%				
1975-1979			100%			
1980-1981			15%	85%		
1982			14%	86%		
1983			12%	88%		
1984-1991				100%		
1992				60%	40%	
1993				20%	80%	
1994					90%	10%
1995					85%	15%
1996					80%	20%

Table C-8: Control Technology Assignments for Gasoline Heavy-Duty Vehicles (percentage of VMT)

Model Years	Uncontrolled	Non-catalyst	Oxidation	Tier 0
≤1981	100%			
1982-1984	95%		5%	
1985-1986		95%	5%	
1987		70%	15%	15%
1988-1989		60%	25%	15%
1990-2003		45%	30%	25%
2004				100%

Table C-9: Control Technology Assignments for Diesel Highway VMT

Vehicle Type/Control Technology	Model Years
Diesel Passenger Cars and Light-Duty Trucks	
Uncontrolled	1966-1982
Moderate control	1983-1995
Advanced control	1996
Heavy-Duty Diesel Vehicles	
Uncontrolled	1966-1972
Moderate control	1983-1995
Advanced control	1996
Motorcycles	
Uncontrolled	1966-1995
Non-catalyst controls	1996

* California VMT only

Table C-10: Emission Factors (g/km) for CH_4 and N_2O and "Fuel Economy" (g CO_2/km)[c] for Highway Mobile Sources

Vehicle Type/Control Technology	N_2O	CH_4	g CO_2/km
Gasoline Passenger Cars			
Low Emission Vehicles[a]	0.0176	0.025	280
Tier 1	0.0288	0.030	285
Tier 0	0.0507	0.040	298
Oxidation Catalyst	0.0322	0.070	383
Non-Catalyst	0.0103	0.120	531
Uncontrolled	0.0103	0.135	506
Gasoline Light-Duty Trucks			
Low Emission Vehicles[a]	0.0249	0.030	396
Tier 1	0.0400	0.035	396
Tier 0	0.0846	0.070	498
Oxidation Catalyst	0.0418	0.090	498
Non-Catalyst	0.0117	0.140	601
Uncontrolled	0.0118	0.135	579
Gasoline Heavy-Duty Vehicles			
Tier 0	0.1729	0.075	1,017
Oxidation Catalyst[b]	0.0870	0.090	1,036
Non-Catalyst Control	0.0256	0.125	1,320
Uncontrolled	0.0269	0.270	1,320
Diesel Passenger Cars			
Advanced	0.0100	0.01	237
Moderate	0.0100	0.01	248
Uncontrolled	0.0100	0.01	319
Diesel Light Trucks			
Advanced	0.0200	0.01	330
Moderate	0.0200	0.01	331
Uncontrolled	0.0200	0.01	415
Diesel Heavy-Duty Vehicles			
Advanced	0.0300	0.04	987
Moderate	0.0300	0.05	1,011
Uncontrolled	0.0300	0.06	1,097
Motorcycles			
Non-Catalyst Control	0.0042	0.26	219
Uncontrolled	0.0054	0.13	266

[a] Applied to California VMT only
[b] Methane emission factor assumed based on light-duty trucks oxidation catalyst value
[c] The carbon emission factor (g CO_2/km) was used as a proxy for fuel economy because of the greater number of significant figures compared to the km/L values presented in (IPCC/UNEP/OECD/IEA 1997).
NA (Not Available)

Table C-11: Emission Factors for CH_4 and N_2O Emissions from Non-Highway Mobile Sources (g/kg fuel)

Vehicle Type/Fuel Type	**N_2O**	**CH_4**
Marine Bunkers (Ocean-Going Ships)		
Residual*	0.08	0.3
Distillate*	0.08	0.3
Boats		
Residual	0.08	0.23
Distillate	0.08	0.23
Gasoline	0.08	0.23
Locomotives		
Residual	0.08	0.25
Diesel	0.08	0.25
Coal	0.08	0.25
Farm Equipment		
Gas/Tractor	0.08	0.45
Other Gas	0.08	0.45
Diesel/Tractor	0.08	0.45
Other Diesel	0.08	0.45
Construction		
Gas Construction	0.08	0.18
Diesel Construction	0.08	0.18
Other Non-Highway		
Gas Snowmobile	0.08	0.18
Gas Small Utility	0.08	0.18
Gas HD Utility	0.08	0.18
Diesel HD Utility	0.08	0.18
Aircraft		
Jet Fuel	NA	0.087
Av. Gas	0.04	2.64

* Methane emission factor value assumed based on value of diesel heavy oil in (IPCC/UNEP/OECD/IEA 1997)
NA (Not Available)

Table C-12: 1996 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,752**	**46,712**	**4,709**
Passenger Cars	3,075	29,883	2,979
Light-Duty Trucks	1,370	13,377	1,435
Heavy-Duty Vehicles	295	3,267	259
Motorcycles	12	185	35
Diesel Highway	**1,753**	**1,318**	**283**
Passenger Cars	35	30	12
Light-Duty Trucks	9	7	4
Heavy-Duty Vehicles	1,709	1,280	267
Non-Highway	**4,183**	**15,424**	**2,201**
Boats and Vessels	244	1,684	460
Locomotives	836	102	44
Farm Equipment	1,012	901	207
Construction Equipment	1,262	1,066	184
Aircraft	151	861	161
Other*	678	10,810	1,144
Total	**10,688**	**63,455**	**7,192**

* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.
Note: Totals may not sum due to independent rounding.

Table C-13: 1995 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,804**	**47,767**	**4,883**
Passenger Cars	3,112	30,391	3,071
Light-Duty Trucks	1,378	13,453	1,478
Heavy-Duty Vehicles	301	3,741	297
Motorcycles	12	182	37
Diesel Highway	**1,839**	**1,318**	**290**
Passenger Cars	35	30	12
Light-Duty Trucks	9	7	4
Heavy-Duty Vehicles	1,795	1,281	274
Non-Highway	**4,241**	**15,278**	**2,207**
Boats and Vessels	244	1,674	436
Locomotives	898	103	45
Farm Equipment	1,007	885	207
Construction Equipment	1,265	1,053	184
Aircraft	150	855	161
Other*	678	10,709	1,175
Total	**10,884**	**64,363**	**7,380**

* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.
Note: Totals may not sum due to independent rounding.

Table C-14: 1994 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**5,063**	**54,778**	**5,507**
Passenger Cars	3,230	33,850	3,367
Light-Duty Trucks	1,503	15,739	1,731
Heavy-Duty Vehicles	318	5,013	375
Motorcycles	11	177	33
Diesel Highway	**1,897**	**1,316**	**300**
Passenger Cars	35	29	12
Light-Duty Trucks	9	7	4
Heavy-Duty Vehicles	1,854	1,280	284
Non-Highway	**4,485**	**15,308**	**2,376**
Boats and Vessels	233	1,663	575
Locomotives	859	104	45
Farm Equipment	1,113	998	229
Construction Equipment	1,443	1,146	204
Aircraft	146	830	159
Other*	692	10,566	1,164
Total	**11,445**	**71,402**	**8,184**

* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.
Note: Totals may not sum due to independent rounding.

Table C-15: 1993 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,913**	**53,375**	**5,248**
Passenger Cars	3,327	35,357	3,427
Light-Duty Trucks	1,289	13,786	1,494
Heavy-Duty Vehicles	286	4,061	296
Motorcycles	11	172	31
Diesel Highway	**1,900**	**1,240**	**288**
Passenger Cars	36	30	12
Light-Duty Trucks	7	6	3
Heavy-Duty Vehicles	1,857	1,205	273
Non-Highway	**4,332**	**15,053**	**2,341**
Boats and Vessels	230	1,651	571
Locomotives	857	108	47
Farm Equipment	1,090	1,011	226
Construction Equipment	1,344	1,061	190
Aircraft	142	821	160
Other*	669	10,400	1,148
Total	**11,145**	**69,668**	**7,878**

* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.
Note: Totals may not sum due to independent rounding.

Table C-16: 1992 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,788**	**53,077**	**5,220**
Passenger Cars	3,268	35,554	3,447
Light-Duty Trucks	1,230	13,215	1,440
Heavy-Duty Vehicles	280	4,145	303
Motorcycles	11	163	30
Diesel Highway	**1,962**	**1,227**	**288**
Passenger Cars	35	28	12
Light-Duty Trucks	7	6	3
Heavy-Duty Vehicles	1,920	1,193	274
Non-Highway	**4,226**	**14,855**	**2,314**
Boats and Vessels	239	1,639	568
Locomotives	858	113	49
Farm Equipment	1,078	993	223
Construction Equipment	1,256	999	178
Aircraft	142	818	162
Other*	653	10,293	1,134
Total	**10,975**	**69,158**	**7,822**

* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Table C-17: 1991 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,654**	**55,104**	**5,607**
Passenger Cars	3,133	36,369	3,658
Light-Duty Trucks	1,215	13,621	1,531
Heavy-Duty Vehicles	296	4,953	384
Motorcycles	10	161	33
Diesel Highway	**2,035**	**1,210**	**290**
Passenger Cars	34	27	11
Light-Duty Trucks	7	5	3
Heavy-Duty Vehicles	1,995	1,177	276
Non-Highway	**4,099**	**14,551**	**2,271**
Boats and Vessels	246	1,624	563
Locomotives	842	109	47
Farm Equipment	1,035	935	213
Construction Equipment	1,197	961	171
Aircraft	141	806	161
Other*	638	10,116	1,116
Total	**10,788**	**70,865**	**8,167**

* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Table C-18: 1990 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,356**	**51,332**	**5,444**
Passenger Cars	2,910	33,746	3,524
Light-Duty Trucks	1,140	12,534	1,471
Heavy-Duty Vehicles	296	4,863	392
Motorcycles	11	190	56
Diesel Highway	**2,031**	**1,147**	**283**
Passenger Cars	35	28	11
Light-Duty Trucks	6	5	2
Heavy-Duty Vehicles	1,989	1,115	269
Non-Highway	**4,167**	**14,622**	**2,270**
Boats and Vessels	235	1,600	555
Locomotives	843	110	48
Farm Equipment	1,028	969	214
Construction Equipment	1,268	1,023	181
Aircraft	143	820	163
Other*	650	10,099	1,109
Total	**10,554**	**67,101**	**7,997**

* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Annex D
Methodology for Estimating Methane Emissions from Coal Mining

The methodology for estimating methane emissions from coal mining consists of two distinct steps. The first step addresses emissions from underground mines. For these mines, emissions were estimated on a mine-by-mine basis and then are summed to determine total emissions. The second step of the analysis involved estimating methane emissions for surface mines and post-mining activities. In contrast to the methodology for underground mines, which used mine-specific data, the methodology for estimating emissions from surface mines and post-mining activities consists of multiplying basin-specific coal production by basin specific emissions factors.

Step 1: Estimate Methane Liberated and Methane Emitted from Underground Mines

Underground mines liberate methane from ventilation systems and from degasification systems. Some mines recover and use methane liberated from degasification systems, thereby reducing methane emissions to the atmosphere. Total methane emitted from underground mines equals methane liberated from ventilation systems, plus methane liberated from degasification systems, minus methane recovered and used.

Step 1.1 Estimate Methane Liberated from Ventilation Systems

All coal mines use ventilation systems for several air quality purposes and to ensure that methane levels remain within safe concentrations. Many coal mines do not have detectable methane emissions, while others emit several million cubic feet per day (MMCFD) from their ventilation systems. On a quarterly basis, the U.S. Mine Safety and Health Administration (MSHA) measures methane emissions levels at underground mines. MSHA maintains a database of measurement data from all underground mines with detectable levels of methane in their ventilation air.[6] Based on the four quarterly measurements, MSHA estimates average daily methane liberated at each of the underground mines with detectable emissions.

For the years 1990 through 1996, EPA obtained MSHA emissions data for a large but incomplete subset all mines with detectable emissions. This subset includes mines emitting at least 0.1 MMCFD for some years and at least 0.5 MMCFD for other years, as shown in Table D-1. Well over 90 percent of all ventilation emissions are concentrated in these subsets. For 1997, EPA obtained the complete MSHA database for all 586 mines with detectable methane emissions. These mines were assumed to account for 100 percent of methane liberated from underground mines.

Using this complete 1997 database, the portion of total emissions accounted for by mines emitting more and less than 0.1 MMCFD or 0.5 MMCFD was estimated. (see Table D-1). These proportions were then applied to the years 1990 through 1996 to account for the less than 10 percent of mines without MSHA data.

Average daily methane emissions were multiplied by 365 days per year to determine annual emissions for each mine. Total ventilation emissions for these mines were estimated by summing emissions from individual mines.

[6] MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

Table D-1: Mine-Specific Data Used to Estimate Ventilation Emissions

Year	Individual Mine Data Used
1990	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1991	1990 Emissions Factors Used Instead of Mine Specific Data
1992	1990 Emissions Factors Used Instead of Mine Specific Data
1993	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1994	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1995	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1996	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1997	All Mines with Detectable Emissions (Assumed to Account for 100% of Total)

*Assumption based on complete set of individual mine data collected for 1997.

Step 1.2 Estimate Methane Liberated from Degasification Systems

Over 20 U.S. coal mines use degasification systems in addition to their ventilation systems for methane control. Coal mines use several different types of degasification systems to remove methane, including vertical wells and horizontal boreholes recover methane prior to mining of the coal seam. Gob wells and cross-measure boreholes recover methane from the overburden (i.e., GOB area) after mining of the seam (primarily in longwall mines).

MSHA collects information about the presence and type of degasification systems in some mines, but does not collect quantitative data on the amount of methane liberated. Thus, the methodology estimated degasification emissions on a mine-by-mine basis based on other sources of available data. Many of the coal mines employing degasification systems have provided EPA with information regarding methane liberated from their degasification systems. For these mines, this reported information was used as the estimate. In other cases in which mines sell methane recovered from degasification systems to a pipeline, gas sales were used to estimate methane liberated from degasification systems (see Step 1.3). Finally, for those mines that do not sell methane to a pipeline and have not provided information to EPA, methane liberated from degasification systems was estimated based on the type of system employed. For example, for coal mines employing gob wells and horizontal boreholes, the methodology assumes that degasification emissions account for 40 percent of total methane liberated from the mine.

Step 1.3: Estimate Methane Recovered from Degasification Systems and Used (Emissions Avoided)

In 1996, all 12 active U.S. coal mines that had developed methane recovery and use projects sold the recovered methane to a pipeline. One coal mine also used some recovered methane in a thermal dryer in addition to selling gas to a pipeline. Where available, state agency gas sales data were used to estimate emissions avoided for these projects. Emissions avoided were attributed to the year in which the coal seam was mined. For example, if a coal mine recovered and sold methane using a vertical well drilled five years in advance of mining, the emissions avoided associated with those gas sales were attributed to the year during which the well was mined-through (five years after the gas was sold). In order to estimate emissions avoided for those coal mines using degasification methods that recover methane in advance of mining, information was needed regarding the amount of gas recovered and the number of years in advance of mining that wells were drilled. In most cases, coal mine operators provided EPA with this information, which was then used to estimate emissions avoided for a particular year. Additionally, several state agencies made production data available for individual wells. For some mines, this individual well data were used to assign gas sales from individual wells to the appropriate emissions avoided year.

Step 2: Estimate Methane Emitted from Surface Mines and Post-Mining Activities

Mine-specific data was not available for estimating methane emissions from surface coal mines or for post-mining activities. For surface mines and post-mining activities, basin-specific coal production was multiplied by a basin-specific emission factors to determine methane emissions.

Step 2.1: Define the Geographic Resolution of the Analysis and Collect Coal Production Data

The first step in estimating methane emissions from surface mining and post-mining activities was to define the geographic resolution of the analysis and to collect coal production data at that level of resolution. The U.S. analysis was conducted by coal basin as defined in Table D-2.

The Energy Information Agency (EIA) Coal Industry Annual reports state- and county-specific underground and surface coal production by year. To calculate production by basin, the state level data were grouped into coal basins using the basin definitions listed in Table D-2. For two states—West Virginia and Kentucky—county-level production data was used for the basin assignments because coal production occurred from geologically distinct coal basins within these states. Table D-2 presents coal basin definitions by basin and by state. Table D-3 presents the coal production data aggregated by basin.

Step 2.2: Estimate Emissions Factors for Each Emissions Type

Emission factors for surface mined coal were developed from the *in situ* methane content of the surface coal in each basin. Based on an analysis presented in EPA (1993), the surface mining emission factors used were from 1 to 3 times the average *in situ* content in the basin. Furthermore, the post-mining emission factors used were assumed to be 25 to 40 percent of the average *in situ* content in the basin. Table D-4 presents the average *in situ* content for each basin, along with the resulting emission factor estimates.

Step 2.3: Estimate Methane Emitted

The total amount of methane emitted was calculated by multiplying the coal production in each basin by the appropriate emission factors.

Total annual methane emissions is equal to the sum of underground mine emissions plus surface mine emissions plus post-mining emissions. Table D-5 and Table D-6 present estimates of methane liberated, methane used, and methane emissions for 1990 through 1997 (1997 is a preliminary estimate).

Table D-2: Coal Basin Definitions by Basin and by State

Basin	States
Northern Appalachian Basin	Maryland, Ohio, Pennsylvania, West VA North
Central Appalachian Basin	Kentucky East, Tennessee, Virginia, West VA South
Warrior Basin	Alabama
Illinois Basin	Illinois, Indiana, Kentucky West
South West and Rockies Basin	Arizona, California, Colorado, New Mexico, Utah
North Great Plains Basin	Montana, North Dakota, Wyoming
West Interior Basin	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas
Northwest Basin	Alaska, Washington
State	**Basin**
Alabama	Warrior Basin
Alaska	Northwest Basin
Arizona	South West And Rockies Basin
Arkansas	West Interior Basin
California	South West And Rockies Basin
Colorado	South West And Rockies Basin
Illinois	Illinois Basin
Indiana	Illinois Basin
Iowa	West Interior Basin
Kansas	West Interior Basin
Kentucky East	Central Appalachian Basin
Kentucky West	Illinois Basin
Louisiana	West Interior Basin
Maryland	Northern Appalachian Basin
Missouri	West Interior Basin
Montana	North Great Plains Basin
New Mexico	South West And Rockies Basin
North Dakota	North Great Plains Basin
Ohio	Northern Appalachian Basin
Oklahoma	West Interior Basin
Pennsylvania.	Northern Appalachian Basin
Tennessee	Central Appalachian Basin
Texas	West Interior Basin
Utah	South West And Rockies Basin
Virginia	Central Appalachian Basin
Washington	Northwest Basin
West Virginia South	Central Appalachian Basin
West Virginia North	Northern Appalachian Basin
Wyoming	North Great Plains Basin

Table D-3: Annual Underground Coal Production (thousand short tons)

Underground Coal Production							
Basin	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Northern Appalachia	103,865	103,450	105,220	77,032	100,122	98,103	106,729
Central Appalachia	198,412	181,873	177,777	164,845	170,893	166,495	171,845
Warrior	17,531	17,062	15,944	15,557	14,471	17,605	18,217
Illinois	69,167	69,947	73,154	55,967	69,050	69,009	67,046
S. West/Rockies	32,754	31,568	31,670	35,409	41,681	42,994	43,088
N. Great Plains	1,722	2,418	2,511	2,146	2,738	2,018	2,788
West Interior	105	26	59	100	147	25	137
Northwest	0	0	0	0	0	0	0
Total	**423,556**	**406,344**	**406,335**	**351,056**	**399,102**	**396,249**	**409,850**
Surface Coal Production							
Basin	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Northern Appalachia	60,761	51,124	50,512	48,641	44,960	39,372	39,788
Central Appalachia	94,343	91,785	95,163	94,433	106,129	106,250	108,869
Warrior	11,413	10,104	9,775	9,211	8,795	7,036	6,420
Illinois	72,000	63,483	58,814	50,535	51,868	40,376	44,754
S. West/Rockies	43,863	42,985	46,052	48,765	49,119	46,643	43,814
N. Great Plains	249,356	259,194	258,281	275,873	308,279	331,367	343,404
West Interior	64,310	61,889	63,562	60,574	58,791	59,116	60,912
Northwest	6,707	6,579	6,785	6,340	6,460	6,566	6,046
Total	**602,753**	**587,143**	**588,944**	**594,372**	**634,401**	**636,726**	**654,007**
Total Coal Production							
Basin	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Northern Appalachia	164,626	154,574	155,732	125,673	145,082	137,475	146,517
Central Appalachia	292,755	273,658	272,940	259,278	277,022	272,745	280,714
Warrior	28,944	27,166	25,719	24,768	23,266	24,641	24,637
Illinois	141,167	133,430	131,968	106,502	120,918	109,385	111,800
S. West/Rockies	76,617	74,553	77,722	84,174	90,800	89,637	86,902
N. Great Plains	251,078	261,612	260,792	278,019	311,017	333,385	346,192
West Interior	64,415	61,915	63,621	60,674	58,938	59,141	61,049
Northwest	6,707	6,579	6,785	6,340	6,460	6,566	6,046
Total	**1,026,309**	**993,487**	**995,279**	**945,428**	**1,033,503**	**1,032,975**	**1,063,857**

Source: EIA (1990-96), Coal Industry Annual. U.S. Department of Energy, Washington, D.C., Table 3.
Note: Totals may not sum due to independent rounding.

Table D-4: Surface and Post-Mining Coal Emission Factors (ft^3 per short ton)

Basin	**Surface Average *in situ* Content**	**Underground Average *in situ* Content**	**Surface Mine Factors**			**Post-Mining Surface Factors**			**Post Mining Underground**		
			Low	**Mid**	**High**	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Northern Appalachia	49.3	49.3	49.3	98.6	147.9	12.3	16.0	19.7	12.3	16.0	19.7
Central Appalachia	49.3	49.3	49.3	98.6	147.9	12.3	16.0	19.7	12.3	16.0	19.7
Warrior	49.3	49.3	49.3	98.6	147.9	12.3	16.0	19.7	12.3	16.0	19.7
Illinois	39.0	39.0	39.0	78.0	117.0	9.8	12.7	15.6	9.8	12.7	15.6
S. West/Rockies	15.3	15.3	15.3	30.6	45.9	3.8	5.0	6.1	3.8	5.0	6.1
N. Great Plains	3.2	3.2	3.2	6.4	9.6	0.8	1.0	1.3	0.8	1.0	1.3
West Interior	3.2	3.2	3.2	6.4	9.6	0.8	1.0	1.3	0.8	1.0	1.3
Northwest	3.2	3.2	3.2	6.4	9.6	0.8	1.0	1.3	0.8	1.0	1.3

Source: EPA (1993), Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress, U.S. Environmental Protection Agency, Air and Radiation, April.

Table D-5: Underground Coal Mining Methane Emissions (billion cubic feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997[b]
Ventilation Output	112	NA	NA	95	96	102	90	96
Adjustment Factor for Mine Data[a]	97.8%	NA	NA	97.8%	97.8%	91.4%	91.4%	100.0%
Ventilation Liberated	114	NA	NA	97	98	111	99	96
Degasification System Liberated	57	NA	NA	49	50	50	51	57
Total Underground Liberated	171	164	162	146	149	161	150	153
Recovered & Used	(15)	(15)	(19)	(24)	(29)	(31)	(35)	(42)
Total	**156**	**149**	**142**	**121**	**119**	**130**	**115**	**112**

[a] Refer to Table D-1
[b] Preliminary estimate.
Note: Totals may not sum due to independent rounding.

Table D-6: Total Coal Mining Methane Emissions (billion cubic feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997*
Underground Mining	156	149	142	121	119	130	115	112
Surface Mining	25	23	23	23	24	22	23	24
Post-Mining (Underground)	33	31	30	27	30	30	31	30
Post-Mining (Surface)	4	4	4	4	4	4	4	4
Total	**218**	**207**	**200**	**175**	**177**	**185**	**172**	**170**

* Preliminary estimate
Note: Totals may not sum due to independent rounding.

Annex E
Methodology for Estimating Methane Emissions from Natural Gas Systems

Step 1: Calculate Emission Estimates for Base Year 1992 Using GRI/EPA Study

The first step in estimating methane emissions from natural gas systems was to develop a detailed base year estimate of emissions. The study by GRI/EPA (1995) divides the industry into four stages to construct a detailed emissions inventory for the year 1992. These stages include: field production, processing, transmission and storage (both underground and liquefied gas storage), and distribution. This study produced emission factors and activity data for over 100 different emission sources within the natural gas system. Emissions for 1992 were estimated by multiplying activity levels by emission factors for each system component and then summing by stage. Since publication, EPA has updated activity data for some of the components in the system. Table E-1 displays the 1992 GRI/EPA activity levels and emission factors for venting and flaring from the field production stage, and the current EPA activity levels and emission factors. The data in Table E-1 is a representative sample of data used to calculate emission from all stages.

Step 2: Collect Aggregate Statistics on Main Driver Variables

As detailed data on each of the over 100 sources were not available for the period 1990 through 1996, activity levels were estimated using aggregate statistics on key drivers, including: number of producing wells (IPAA 1997), number of gas plants (AGA 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997), miles of transmission pipeline (AGA, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997), miles of distribution pipeline (AGA 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997), miles of distribution services (AGA 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997), and energy consumption (EIA 1996a). Data on the distribution of gas mains by material type was not available for certain years from AGA. For those years, the average distribution by type was held constant. Table E-2 provides the activity levels of some of the key drivers in the natural gas analysis.

Step 3: Estimate Emission Factor Changes Over Time

For the period 1990 through 1995, the emission factors were held constant, based on 1992 values. An assumed improvement in technology and practices was estimated to reduce emission factors by 5 percent by the year 2020. This assumption, annualized, amounts to a 0.2 percent decline in the 1996 emission factors.

Step 4: Estimate Emissions for Each Source

Emissions were estimated by multiplying the activity levels by emission factors. Table E-3 provides emission estimates for venting and flaring emissions from the field production stage.

Table E-1: 1992 Data and Emissions (Mg) for Venting and Flaring from Natural Gas Field Production Stage

	GRI/EPA Values			*EPA Adjusted Values*		
Activity	**Activity Data**	**Emission Factor**	**Emissions**	**Activity Data**	**Emission Factor**	**Emissions**
Drilling and Well Completion						
Completion Flaring	844 compl/yr	733 scf/comp	11.9	400 compl/yr	733 scf/comp	5.63
Normal Operations						
Pneumatic Device Vents	249,111 controllers	345 scfd/device	602,291	249,111 controllers	345 scfd/device	602,291
Chemical Injection Pumps	16,971 active pumps	248 scfd/pump	29,501	16,971 active pumps	248 scfd/pump	29,502
Kimray Pumps	11,050,000 MMscf/yr	368 scf/MMscf	78,024	7,380,194 MMscf/yr	992 scf/MMscf	140,566
Dehydrator Vents	12,400,000 MMscf/yr	276 scf/MMscf	65,608	8,200,215 MMscf/yr	276 scf/MMscf	43,387
Compressor Exhaust Vented						
Gas Engines	27,460 MMHPhr	0.24 scf/HPhr	126,536	27,460 MMHPhr	0.24 scf/HPhr	126,535
Routine Maintenance						
Well Workovers						
Gas Wells	9,392 w.o./yr	2,454 scfy/w.o.	443	9,392 w.o./yr	2,454 scfy/w.o.	443
Well Clean Ups (LP Gas Wells)	114,139 LP gas wells	49,570 scfy/LP well	108,631	114,139 LP gas wells	49,570 scfy/LP well	108,631
Blowdowns						
Vessel BD	255,996 vessels	78 scfy/vessel	383	242,306 vessels	78 scfy/vessel	363
Pipeline BD	340,000 miles (gath)	309 scfy/mile	2,017	340,200 miles (gath)	309 scfy/mile	2,018
Compressor BD	17,112 compressors	3,774 scfy/comp	1,240	17,112 compressors	3,774 scfy/comp	1,240
Compressor Starts	17,112 compressors	8,443 scfy/comp	2,774	17,112 compressors	8,443 scfy/comp	2,774
Upsets						
Pressure Relief Valves	529,440 PRV	34.0 scfy/PRV	346	529,440 PRV	34.0 scfy/PRV	346
ESD	1,115 platforms	256,888 scfy/plat	5,499	1,372 platforms	256,888 scfy/plat	6,767
Mishaps	340,000 miles	669 scfy/mile	4,367	340,200 miles	669 scfy/mile	4,370

Table E-2: Activity Factors for Key Drivers

Variable	Unit	1990	1991	1992	1993	1994	1995	1996
Transmission Pipelines Length	miles	280,100	281,600	284,500	269,600	268,300	264,900	257,000
Wells								
GSAM Appalachia Wells [a]	# wells	120,162	121,586	123,685	124,708	122,021	123,092	122,700
GSAM N Central Associated Wells [a]	# wells	3,862	3,890	3,852	3,771	3,708	3,694	3,459
GSAM N Central Non-Associated Wells [a]	# wells	3,105	3,684	4,317	4,885	5,813	6,323	7,073
GSAM Rest of US Wells [a]	# wells	145,100	147,271	152,897	156,568	160,011	164,750	173,928
GSAM Rest of US Associated Wells [a]	# wells	256,918	262,441	253,587	249,265	248,582	245,338	246,598
Appalch. + N. Central Non-Assoc. + Rest of US	# wells	268,367	272,541	280,899	286,161	287,845	294,165	303,701
Platforms								
Gulf of Mexico Off-shore Platforms	# platforms	3,798	3,834	3,800	3,731	3,806	3,868	3,846
Rest of U.S. (offshore platforms)	# platforms	24	24	24	24	23	23	24
N. Central Non-Assoc. + Rest of US Wells	# platforms	148,205	150,955	157,214	161,453	165,824	171,073	181,001
Gas Plants								
Number of Gas Plants	# gas plants	761	734	732	726	725	675	623
Distribution Services								
Steel - Unprotected	# of services	5,500,993	5,473,625	5,446,393	5,419,161	5,392,065	5,365,105	5,388,279
Steel - Protected	# of services	19,916,202	20,352,983	20,352,983	20,512,366	20,968,447	21,106,562	21,302,429
Plastic	# of services	16,269,414	17,654,006	17,681,238	18,231,903	19,772,041	20,270,203	20,970,924
Copper	# of services	228,240	233,246	233,246	235,073	240,299	241,882	244,127
Total	# of services	41,914,849	43,713,860	43,713,860	44,398,503	46,372,852	46,983,752	47,905,759
Distribution Mains								
Steel - Unprotected	miles	491,120	492,887	496,839	501,480	497,051	499,488	468,833
Steel - Protected	miles	91,267	90,813	90,361	89,909	89,460	89,012	88,567
Cast Iron	miles	52,644	52,100	51,800	50,086	48,542	48,100	47,100
Plastic	miles	202,269	221,600	244,300	266,826	284,247	294,400	329,700
Total	miles	837,300	857,400	883,300	908,300	919,300	931,000	934,200

[a] GSAM is the Gas Systems Analysis Model (GSAM 1997) of the Federal Energy Technology Center of the U.S. Department of Energy. It is a supply, demand and transportation model.

Table E-3: Emission Estimates for Venting and Flaring from the Field Production Stage (Mg)

Activity	1990	1991	1992	1993	1994	1995	1996
Drilling and Well Completion							
Completion Flaring	5.4	5.5	5.6	5.7	5.8	5.9	6.1
Normal Operations							
Pneumatic Device Vents	567,778	578,313	602,291	618,531	635,276	655,386	691,999
Chemical Injection Pumps	36,449	37,323	39,053	40,277	41,668	43,111	45,664
Kimray Pumps	134,247	136,380	140,566	143,211	144,040	147,191	151,565
Dehydrator Vents	41,436	42,095	43,387	44,203	44,459	45,432	46,782
Compressor Exhaust Vented							
Gas Engines	119,284	121,498	126,535	129,947	133,465	137,690	145,382
Routine Maintenance							
Well Workovers							
Gas Wells	531	540	556	567	570	582	600
Well Clean Ups (LP Gas Wells)	101,118	102,725	105,878	107,870	108,494	110,868	114,162
Blowdowns							
Vessel BD	256	261	271	278	284	292	306
Pipeline BD	1,710	1,729	1,772	1,772	1,818	1,852	1,908
Compressor BD	1,548	1,573	1,627	1,662	1,687	1,730	1,802
Compressor Starts	3,462	3,518	3,640	3,718	3,773	3,871	4,031
Upsets							
Pressure Relief Valves	326	332	346	355	365	376	397
ESD	6,764	6,827	6,767	6,646	6,773	6,882	6,834
Mishaps	925	936	959	974	984	1,003	1,033

Annex F
Methodology for Estimating Methane Emissions from Petroleum Systems

The methodology for estimating methane emissions from petroleum systems is being updated. EPA anticipates that current methodology understates emissions, and that the new methodology will be incorporated into future inventories.

Step 1: Production Field Operations

The American Petroleum Institute (API) publishes active oil well data in reports such as the *API Basic Petroleum Data Book*. To estimate activity data, the percentage of oil wells that were not associated with natural gas production, averaging approximately 56.4 percent over the period 1990 through 1996, was multiplied by the total number of wells in the United States. This number was then multiplied by per well emission factors for fugitive emissions and routine maintenance from Tilkicioglu & Winters (1989). Table F-1 displays the activity data, emission factors, and emissions estimates used.

Step 2: Crude Oil Storage

Methane emissions from storage were calculated as a function of annual U.S. crude stocks less strategic petroleum stocks for each year, obtained from annual editions of the *Petroleum Supply Annual* (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997). These stocks were multiplied by emission factors from Tilkicioglu & Winters (1989) to estimate emissions. Table F-2 displays the activity data, emission factors, and emissions estimates used.

Step 3: Refining

Methane emissions from refinery operations were based on U.S. refinery working storage capacity, found in annual editions of the *Petroleum Supply Annual* (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997). This capacity was multiplied by an emission factor from Tilkicioglu & Winters (1989) to estimate emissions. Table F-3 provides the activity data, emission factors, and emissions estimates used.

Step 4: Tanker Operations

Methane emissions from the transportation of petroleum on marine vessels were estimated using activity data on crude oil imports, U.S. crude oil production, Alaskan crude oil production, and Alaskan refinery crude oil capacity. All activity data were taken from annual editions of the *Petroleum Supply Annual* (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997).

Tilkicioglu & Winters (1989) identified three sources of emissions in the transportation of petroleum. These are emissions from loading Alaskan crude oil onto tankers, emissions from crude oil transfers to terminals, and ballast emissions.

Step 4.1: Loading Alaskan Crude Oil onto Tankers

The net amount of crude oil transported by tankers was determined by subtracting Alaskan refinery capacity from Alaskan crude oil production. This net amount was multiplied by an emission factor from Tilkicioglu & Winters (1989) to estimate emissions. The activity data and emissions estimates are shown in Table F-4.

Step 4.2: Crude Oil Transfers to Terminals

Methane emissions from crude oil transfers were taken from the total domestic crude oil transferred to terminals. This amount was assumed to be 10 percent of total domestic crude oil production less Alaskan crude oil production.

To estimate emissions, this transferred amount was multiplied by an emission factor from Tilkicioglu & Winters (1989). The activity data and emissions estimates are shown in Table F-5.

Step 4.3: Ballast Emissions

Ballast emissions are emitted from crude oil transported on marine vessels. This amount was calculated from the sum of Alaskan crude oil on tankers, the amount of crude oil transferred to terminals, and all crude oil imports less Canadian imports. Ballast volume was assumed to be 17 percent of this sum (Tilkicioglu & Winters 1989). This amount was then multiplied by an emission factor to estimate emissions. The activity data and emissions estimates are shown in Table F-6.

Total emissions from tanker operations are shown in Table F-7.

Step 5: Venting and Flaring

Methane emissions from venting and flaring were based on 1990 emissions estimates from EPA (1993) and were held constant through 1996 due to the lack of data available to assess the change in emissions.

Table F-1: Emissions from Petroleum Production Field Operations

Activity	Units	1990	1991	1992	1993	1994	1995	1996
Total Oil Wells		587,762	610,204	594,189	583,879	581,657	574,483	574,419
% Not Assoc. w/ Natural Gas	%	55.6%	56.4%	56.7%	56.7%	56.6%	56.7%	56.5%
Oil Wells in Analysis		326,982	343,873	336,749	330,843	329,366	325,451	324,362
Emission Factors								
Fugitive	kg/well/yr	72						
Routine Maintenance	kg/well/yr	0.15						
Emissions								
Fugitive	mill kg/yr	23.5	24.8	24.3	23.9	23.7	23.4	23.4
Routine Maintenance	mill kg/yr	0.05	0.05	0.05	0.05	0.05	0.05	0.05

Table F-2: Emissions from Petroleum Storage

Activity	Units	1990	1991	1992	1993	1994	1995	1996
Total Crude Stocks	1000 barrels/yr	908,387	893,102	892,864	922,465	928,915	894,968	849,669
Strategic Petroleum Stocks	1000 barrels/yr	585,692	568,508	574,724	587,080	591,670	591,640	566,000
Crude Oil Storage	1000 barrels/yr	322,695	324,594	318,140	335,385	337,245	303,328	283,669
Emission Factors								
Breathing	kg CH_4/brl/yr	0.002612						
Working	kg CH_4/brl/yr	0.002912						
Fugitive	kg CH_4/brl/yr	4.99×10^{-5}						
Emissions								
Breathing	kg/yr	842,892	847,853	830,994	876,039	880,897	792,305	740,955
Working	kg/yr	939,602	945,131	926,339	976,552	981,968	883,210	825,969
Fugitive	kg/yr	16,118	16,213	15,891	16,752	16,845	15,151	14,169
Total Emissions	**mill. kg/yr**	**1.80**	**1.81**	**1.77**	**1.87**	**1.88**	**1.69**	**1.58**

Table F-3: Emissions from Petroleum Refining

Activity (Jan 1)	Units	1990	1991	1992	1993	1994	1995	1996
Total Refinery Storage Capacity	1000 barrels/yr	174,490	171,366	167,736	170,823	164,364	161,305	158,435
Storage Emission Factor	Mg CH_4/brl/yr	5.9×10^{-5}						
Emissions	mill. kg/yr	10.29	10.10	9.89	10.07	9.69	9.51	9.34

Table F-4: Emissions from Petroleum Transportation: Loading Alaskan Crude Oil onto Tankers (Barrels/day*)

Activity	1990	1991	1992	1993	1994	1995	1996
Alaskan Crude	1,773,452	1,798,216	1,718,690	1,582,175	1,558,762	1,484,000	1,393,000
Alaskan Refinery Crude Capacity	229,850	239,540	222,500	256,300	261,000	275,152	283,350
Net Tankered	1,543,602	1,558,676	1,496,190	1,325,875	1,297,762	1,208,848	1,109,650
Conversion Factor (gal oil/ barrel oil)	42						
Emission factor (lbs/gallon)	0.001						
Emissions @ Loading AK (lbs/day)	64,831	65,464	62,840	55,687	54,506	50,772	46,605
Methane Content of Gas (%)	20.80%						
Emissions @ Loading AK (mill kg/yr)	2.23	2.26	2.17	1.92	1.88	1.75	1.61

* Unless otherwise noted

Table F-5: Emissions from Petroleum Transportation: Crude Oil Transfers to Terminals (Barrels/day*)

Activity	1990	1991	1992	1993	1994	1995	1996
US Crude Production	7,355,307	7,416,545	7,190,773	6,846,666	6,661,578	6,560,000	6,465,000
AK Crude Production	1,773,452	1,798,216	1,718,690	1,582,175	1,558,762	1,484,000	1,393,000
US Crude - AK Crude	5,581,855	5,618,329	5,472,082	5,264,490	5,102,816	5,076,000	5,072,000
10% transported to terminals	558,185	561,833	547,208	526,449	510,282	507,600	507,200
Conversion Factor (gal oil/ barrel oil)	42						
Emission factor (lbs/gallon)	0.001						
Emissions from Transfers (lbs/day)	23,444	23,597	22,983	22,111	21,432	21,319	21,302
Methane Content of Gas (%)	20.80%						
Emissions from Transfers (mill kg/yr)	0.81	0.81	0.79	0.76	0.74	0.73	0.73

* Unless otherwise noted

Table F-6: Emissions from Petroleum Transportation: Ballast Emissions (Barrels/day*)

Activity	1990	1991	1992	1993	1994	1995	1996
Crude Imports (less Canadian)	5,251,701	5,038,786	5,300,616	5,886,921	6,079,773	6,125,482	6,909,429
Alaskan Crude (Net Tankered)	1,543,602	1,558,676	1,496,190	1,325,875	1,297,762	1,208,848	1,109,650
10% Crude Prod. Transported to terminals	558,185	561,833	547,208	526,449	510,282	507,600	507,200
Conversion Factor (gal oil/ barrel oil)	42						
Emission factor (lbs/1000 gallons)	1.4						
Crude Oil Unloaded	7,353,489	7,159,296	7,344,015	7,739,245	7,887,816	7,841,930	8,526,279
Ballast Volume (17% of Crude Unloaded)	1,250,093	1,217,080	1,248,483	1,315,672	1,340,929	1,333,128	1,449,467
Ballast Emissions (lbs/day)	73,505	71,564	73,411	77,361	78,847	78,388	85,229
Methane Content of Gas (%)	20.80%						
Ballast Emissions (mill kg/yr)	2.53	2.47	2.53	2.67	2.72	2.70	2.94

* Unless otherwise noted

Table F-7: Total Methane Emissions from Petroleum Transportation

Year	Million kg/yr
1990	5.6
1991	5.5
1992	5.5
1993	5.4
1994	5.3
1995	5.2
1996	5.3

Annex G
Methodology for Estimating Methane Emissions from Enteric Fermentation

Step 1: Collect Livestock Population Data

All livestock population data, except for horses, was taken from U.S. Department of Agriculture (USDA) statistical reports. For each animal category, the USDA publishes monthly, annual, and multi-year livestock population and production estimates. Multi-year reports include revision to earlier published data. Recent reports were obtained from the USDA Economics and Statistics System website, at <http://www.mannlib.cornell.edu/usda/>, while historical data were downloaded from the USDA-National Agricultural Statistics Service (NASS) website at <http://www.usda.gov/nass/pubs/dataprd1.htm>.

The Food and Agriculture Organization (FAO) publish horse population data. These data were accessed from the FAOSTAT database at <http://apps.fao.org/>. Table G-1 summarizes the published population data by animal type.

Step 2: Estimate Emission Factors for Dairy Cows

Regional dairy cow emission factors from the 1993 Report to Congress (EPA 1993) were used as the starting point for the analysis. These emission factors were used to calibrate a model of methane emissions from dairy cows. The model applies revised regional emission factors that reflect changes in milk production per cow over time. Increases in milk production per cow, in theory, require increases in feed intake, which lead to higher methane emissions per cow. Table G-2 presents the emission factors per head by region used for dairy cows and milk production. The regional definitions are from EPA (1993).

Step 3: Estimate Methane Emissions from Dairy Cattle

Dairy cow emissions for each state were estimated by multiplying the published state populations by the regional emission factors, as calculated in Step 2. Dairy replacement emissions were estimated by multiplying national replacement populations by a national emission factor. The USDA reported the number of replacements 12 to 24 months old as “milk heifers.” It is assumed that the number of dairy cow replacements 0 to 12 months old was equivalent to the number 12 to 24 months old replacements.

Step 4: Estimate Methane Emissions from Beef Cattle

Beef cattle methane emissions were estimated by multiplying published cattle populations by emission factors. Emissions from beef cows and replacements were estimated using state population data and regional emission developed in EPA (1993), as shown in Table G-3. Emissions from slaughter cattle and bulls were estimated using national data and emission factors. The emission factors for slaughter animals represent their entire life, from birth to slaughter. Consequently, the emission factors were multiplied by the national data on total steer and heifer slaughters rather than live populations of calves, heifers, and steers grown for slaughter. Slaughter population numbers were taken from and USDA datasets. The Weanling and Yearling mix was unchanged from earlier estimates derived from discussions with industry representatives.

Step 5: Estimate Methane Emissions from Other Livestock

Methane emissions from sheep, goats, swine, and horses were estimated by multiplying published national population estimates by the national emission factor for each year.

A summary of emissions is provided in Table G-4. Emission factors, national average or regional, are shown by animal type in Table G-5.

Table G-1: Livestock Population (thousand head)

Animal Type	1990	1991	1992	1993	1994	1995	1996
Dairy							
Cows	10,007	9,883	9,714	9,679	9,514	9,494	9,409
Replacements 0-12	4,135	4,097	4,116	4,088	4,072	4,021	3,902
Replacements 12-24	4,135	4,097	4,116	4,088	4,072	4,021	3,902
Beef							
Cows	32,677	32,960	33,453	34,132	35,325	35,628	35,414
Replacements 0-12	5,141	5,321	5,621	5,896	6,133	6,087	5,839
Replacements 12-24	5,141	5,321	5,621	5,896	6,133	6,087	5,839
Slaughter-Weanlings	5,199	5,160	5,150	5,198	5,408	5,612	5,580
Slaughter-Yearlings	20,794	20,639	20,600	20,794	21,632	22,450	22,322
Bulls	2,180	2,198	2,220	2,239	2,304	2,395	2,346
Other							
Sheep	11,356	11,174	10,797	10,201	9,742	8,886	8,454
Goats	2,545	2,475	2,645	2,605	2,595	2,495	2,495
Horses	5215	5650	5650	5850	5900	6000	6,000
Hogs	54,014	56,478	58,532	57,999	60,018	59,792	56,716

Table G-2: Dairy Cow Emission Factors and Milk Production Per Cow

Region	1990	1991	1992	1993	1994	1995	1996
Dairy Cow Emission Factors (kg/head)							
North Atlantic	116.2	118.8	121.3	121.0	122.3	124.7	124.8
South Atlantic	127.7	128.7	132.3	132.2	134.5	134.4	132.9
North Central	105.0	105.7	107.8	107.6	109.8	111.2	110.0
South Central	116.2	116.1	117.9	119.2	121.1	122.2	120.9
West	130.4	129.4	132.7	132.3	135.6	134.8	137.3
Milk Production (kg/year)							
North Atlantic	6,574	6,811	7,090	7,055	7,185	7,424	7,440
South Atlantic	6,214	6,300	6,622	6,608	6,813	6,792	6,673
North Central	6,334	6,413	6,640	6,627	6,862	6,987	6,881
South Central	5,696	5,687	5,849	5,971	6,148	6,248	6,128
West	8,339	8,255	8,573	8,530	8,874	8,789	9,047

Table G-3: Emission factors Beef Cows and Replacements (kg/head/yr)

Region	Replacements (0-12)	Replacements (12-24)	Mature Cows
North Atlantic	19.2	63.8	61.5
South Atlantic	22.7	67.5	70.0
North Central	20.4	60.8	59.5
South Central	23.6	67.7	70.9
West	22.7	64.8	69.1

Table G-4: Emissions from Livestock Enteric Fermentation (Tg)

Animal Type	1990	1991	1992	1993	1994	1995	1996
Dairy	1.47	1.46	1.47	1.47	1.47	1.47	1.46
Cows	1.15	1.14	1.15	1.15	1.15	1.16	1.15
Replacements 0-12	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Replacements 12-24	0.24	0.24	0.24	0.24	0.24	0.24	0.23
Beef	3.95	3.98	4.04	4.12	4.27	4.34	4.29
Cows	2.18	2.20	2.23	2.28	2.36	2.38	2.36
Replacements 0-12	0.11	0.12	0.13	0.13	0.14	0.14	0.13
Replacements 12-24	0.33	0.35	0.37	0.38	0.40	0.40	0.38
Slaughter-Weanlings	0.12	0.12	0.12	0.12	0.12	0.13	0.13
Slaughter-Yearlings	0.98	0.98	0.97	0.98	1.02	1.06	1.06
Bulls	0.22	0.22	0.22	0.22	0.23	0.24	0.23
Other	0.28	0.29	0.29	0.29	0.29	0.28	0.27
Sheep	0.09	0.09	0.09	0.08	0.08	0.07	0.07
Goats	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Horses	0.09	0.10	0.10	0.11	0.11	0.11	0.11
Hogs	0.08	0.08	0.09	0.09	0.09	0.09	0.09
Total	**5.70**	**5.73**	**5.80**	**5.88**	**6.03**	**6.10**	**6.02**

Table G-5: Enteric Fermentation Emission Factors

Animal Type	kg/head/year
Dairy	
Cows	regional
Replacements 0-12	19.6
Replacements 12-24	58.8
Beef	
Cows	regional
Replacements 0-12	regional
Replacements 12-24	regional
Slaughter-Weanlings	23.1
Slaughter-Yearlings	47.3
Bulls	100.0
Other	
Sheep	8.0
Goats	5.0
Horses	18.0
Hogs	1.5

Annex H

Methodology for Estimating Methane Emissions from Manure Management

Step 1: Collect Livestock Population Data

All livestock population data, except for horses, were taken from U.S. Department of Agriculture (USDA) statistical reports. For each animal category, the USDA publishes monthly, annual, and multi-year livestock population and production estimates. Multi-year reports include revisions to earlier published data. Recent reports were obtained from the USDA Economics and Statistics System website, at <http://www.mannlib.cornell.edu/usda/>, while historical data were downloaded from the USDA National Agricultural Statistics Service (NASS) website at <http://www.usda.gov/nass/pubs/dataprd1.htm>.

Dairy cow and swine population data by farm size for each state, used in Step 2, were found in the *1992 Census of Agriculture* published by the U.S. Department of Commerce (DOC). This census is conducted every five years. Data from the census were obtained from the USDA NASS website at <http://www.nass.usda.gov/census/>.

The Food and Agriculture Organization (FAO) publishes horse population data. These data weree accessed from the FAOSTAT database at <http://apps.fao.org/>. Table H-1 summarizes the published population data by animal type.

Step 2: Estimate State Methane Conversion Factors for Dairy Cows and Swine

Data from EPA (1993) were used for assessing dairy and swine manure management practices by farm size. Based on this assessment, an average methane conversion factor (MCF) was assigned to each farm size category for dairy and swine farms, indicating the portion of the methane producing potential realized. Because larger farms tend to use liquid manure management systems, which produce more methane, the MCFs applied to them were higher for smaller farm sizes.

Using the dairy cow and swine populations by farm size in the DOC *Census of Agriculture* for each state, weighted average dairy and swine MCFs were calculated for each state. The MCF value for each state reflected the distribution of animals among farm sizes within the state. Table H-2 provides estimated MCF values.

Step 3: Estimate Methane Emissions from Swine

For each state, the total swine population was multiplied by volatile solids (VS) production rates to determine total VS production. Estimated state level emissions were calculated as the product of total VS production multiplied by the maximum methane production potential for swine manure (B_o), and the state MCF. Total U.S. emissions are the sum of the state level emissions. The VS production rate and maximum methane production potential are shown in Table H-3.

Step 4: Estimate Methane Emissions from Dairy Cattle

Methane emissions from dairy cow manure were estimated using the same method as emissions from swine (Step 3), but with an added analysis to estimate changes in manure production associated with changes in feed intake, or dry matter intake (DMi). It is assumed that manure and VS production will change linearly with changes in dry matter intake (DMi).

Changes in DMi were calculated reflecting changes in feed intake associated with changes in milk production per cow per year. To estimate the changes in feed intake, a simplified emission factor model was used for dairy cow enteric fermentation emissions (see Annex G). This model estimates the change in DMi over time relative to 1990, which was used to calculate VS production by dairy cows by state, as summarized in the following equation: (Dairy cow population) x (VS produced per cow) x (DMi scaling factor). Methane emissions were then calculated as follows:

(VS produced) x (Maximum methane production potential for dairy cow manure) x (State-specific MCF). Total emissions were finally calculated as the sum of the state level emissions. The 1990 VS production rate and maximum methane production potential are shown in Table H-3.

Step 5: Estimate Methane Emissions for Other Animals

The 1990 methane emissions for the other animal types were estimated using the detailed method described above for dairy cows and swine (EPA 1993). This process was not repeated for subsequent years for these other animal types. Instead, national populations of each of the animal types were used to scale the 1990 emissions estimates to the period 1991 through 1996.

Emission estimates are summarized in Table H-4.

Table H-1: Livestock Population (1000 head)

	1990	1991		1993	1994		1996
Dairy Cattle		**13,980**	**13,830**		**13,686**	**13,514**	
Dairy Cows	10,007		9,714	9,679		9,493	9,408
	4,135	4,097		4,088	4,072		3,902
Swine		**56,478**	**58,532**		**60,018**	**59,792**	
Beef Cattle	**86,065**		**88,546**	**90,317**		**94,364**	**93,683**
	7,252	7,927		7,838	8,063		7,822
Feedlot Heifers		4,144	3,884		4,088	3,934	
Feedlot Cow/Other	88		92	95		97	96
	2,180	2,198		2,239	2,304		2,346
NOF Calves		23,854	24,118		24,692	25,184	
NOF Heifers	8,740		9,261	9,727		10,790	10,800
	7,554	7,356		8,081	8,108		8,594
NOF Cows		32,860	33,359		35,227	35,531	
Sheep	**11,356**		**10,797**	**10,201**		**8,886**	**8,454**
	7,961	7,799		7,140	6,775		5,875
Rams/Weth>1yr		361	350		314	282	
Ewes<1yr	1,491		1,432	1,349		1,167	1,107
	381	373		348	332		282
Sheep on Feed		1,177	1,093		1,044	957	
Goats	**2,545**		**2,645**	**2,605**		**2,495**	**2,495**
	1,703,037	**1,767,513**		**1,895,851**	**1,971,404**		**2,091,364**
Hens>1yr		117,178	121,103		134,876	133,767	
Pullets laying	153,916		163,397	158,938		164,526	165,304
	34,222	34,272		33,833	32,808		31,316
Pullets<3mo		42,344	45,160		44,875	45,494	
Chickens	6,546		7,113	7,240		7,641	7,243
	1,172,830	1,227,430		1,338,862	1,403,508		1,519,640
Other (Lost)		7,278	7,025		12,744	8,152	
Other (Sold)	41,672		41,538	39,606		40,917	39,588
	128,384	129,505		130,750	131,375		137,595
Horses		**5,650**	**5,850**		**6,000**	**6,000**	

Table H-2: Dairy Cow and Swine Methane Conversion Factors

State	Dairy Cow	Swine	State	Dairy Cow	Swine
AK	0.35	0.35	MT	0.16	0.39
AL	0.23	0.28	NC	0.20	0.65
AR	0.45	0.59	ND	0.05	0.22
AZ	0.09	0.68	NE	0.08	0.34
CA	0.44	0.44	NH	0.12	0.36
CO	0.31	0.46	NJ	0.13	0.26
CT	0.19	0.01	NM	0.42	0.47
DE	0.21	0.29	NV	0.36	0.50
FL	0.41	0.23	NY	0.11	0.22
GA	0.27	0.35	OH	0.07	0.30
HI	0.40	0.40	OK	0.13	0.31
IA	0.04	0.38	OR	0.25	0.35
ID	0.23	0.27	PA	0.06	0.35
IL	0.07	0.42	RI	0.07	0.59
IN	0.06	0.43	SC	0.29	0.40
KS	0.09	0.33	SD	0.06	0.26
KY	0.06	0.30	TN	0.14	0.28
LA	0.19	0.30	TX	0.31	0.30
MA	0.13	0.40	UT	0.21	0.34
MD	0.15	0.42	VA	0.17	0.34
ME	0.10	0.01	VT	0.11	0.09
MI	0.12	0.42	WA	0.29	0.29
MN	0.04	0.38	WI	0.05	0.27
MO	0.07	0.33	WV	0.11	0.11
MS	0.17	0.35	WY	0.12	0.20

Table H-3: Dairy Cow and Swine Constants

Description	Dairy Cow	Swine	Source
Typical Animal Mass (kg)	640	150	ASAE 1995
kg VS/day per 1000 kg mass	10	8.5	ASAE 1995
Maximum methane generation potential (B_o) m^3 methane/kg VS	0.24	0.47	EPA 1992

Animal Type	1990		1992	1993		1995
Dairy Cattle		**0.75**		**0.77**		**0.79**
Dairy Cows		0.59		0.61		0.63
Dairy Heifers		0.16		0.16		0.16
Swine		**1.44**		**1.51**		**1.60**
Beef Cattle		**0.20**		**0.21**		**0.22**
Feedlot Steers		0.03		0.03		0.03
Feedlot Heifers		0.02		0.02		0.02
Feedlot Cow/Other		0.00		0.00		0.00
NOF Bulls		0.01		0.01		0.01
NOF Calves		0.02		0.02		0.02
NOF Heifers		0.02		0.02		0.02
NOF Steers		0.01		0.02		0.02
NOF Cows		0.10		0.10		0.11
Sheep		**0.004**		**0.003**		**0.003**
Ewes > 1 yr		0.003		0.003		0.002
Rams/Weth > 1 yr		0.000		0.000		0.000
Ewes < 1 yr		0.000		0.000		0.000
Rams/Weth < 1 yr		0.000		0.000		0.000
Sheep on Feed		0.000		0.000		0.000
Goats		**0.001**		**0.001**		**0.001**
Poultry		**0.27**		**0.28**		**0.30**
Hens > 1 yr		0.05		0.06		0.06
Pullets laying		0.06		0.06		0.06
Pullets > 3 mo		0.01		0.01		0.01
Pullets < 3 mo		0.01		0.01		0.01
Chickens		0.00		0.00		0.00
Broilers		0.10		0.11		0.12
Other (Lost)		0.00		0.00		0.00
Other (Sold)		0.01		0.01		0.01
Turkeys		0.03		0.03		0.03
Horses		**0.03**		**0.03**		**0.03**

Annex I
Methodology for Estimating Methane Emissions from Landfills

Landfill methane is produced from a complex process of waste decomposition and subsequent fermentation under anaerobic conditions. The total amount of methane produced in a landfill from a given amount of waste and the rate at which it is produced depends upon the characteristics of the waste, the climate, and operating practices at the landfill. To estimate the amount of methane produced in a landfill in given year the following information is needed: quantity of waste in the landfill, the waste characteristics, the residence time of the waste in the landfill, and landfill management practices.

The amount of methane emitted from a landfill is less than the amount of methane produced in a landfill. If no measures are taken to extract the methane, a portion of the methane will oxidize as it travels through the top layer of the landfill cover. The portion of the methane that oxidizes turns primarily to carbon dioxide (CO_2). If the methane is extracted and combusted (e.g., flared or used for energy), then that portion of the methane produced in the landfill will not be emitted as methane, but again would be converted to CO_2. In general, the CO_2 emitted is of biogenic origin and primarily results from the decomposition—either aerobic or anaerobic—of organic matter such as food or yard wastes.[7]

To take into account the inter-related processes of methane production in the landfill and methane emission, this analysis relied on a simulation of the population of landfills and waste disposal. A starting population of landfills was initialized with characteristics from the latest survey of municipal solid waste (MSW) landfills (EPA 1988). Using actual national waste disposal data, waste was simulated to be placed in these landfills each year from 1990 to 1996. If landfills reach their design capacity, they were simulated to have closed. New landfills were simulated to open only if annual disposal capacity was less than total waste disposal. Of note is that closed landfills continue to produce and emit methane for many years. This analysis tracks these closed landfills throughout the analysis period, and includes their estimated methane production and emissions.

Using this approach, the age of the waste in each landfill was tracked explicitly. This tracking allowed the annual methane production in each landfill to be estimated. Methane produced in industrial landfills was also estimated. It was assumed to be 7 percent of the total methane produced in MSW landfills. Finally, methane recovered and combusted and methane oxidized were subtracted to estimate final methane emissions.

Using this approach, landfill population and waste disposal characteristics were simulated over time explicitly, thereby allowing the time-dependent nature of methane production to be modeled. However, the characteristics used to initialize the landfill population in the model were relatively old and may not represent the current set of operating landfills adequately. There is also uncertainty in the methane production equation developed in EPA (1993), as well as in the estimate of methane oxidation (10 percent).

Step 1: Estimate Municipal Solid Waste in Place Contributing to Methane Emissions

The landfill population model was initialized to define the population of landfills at the beginning of 1990. Waste was simulated to be placed into these landfills for the years 1990 through 1996 using data on the total waste landfilled from Biocycle (1997). The annual acceptance rates of the landfills were used to apportion the total waste by landfill. More waste was preferentially disposed in "Large" landfills (see Table I-3), reflecting the trend toward fewer and more centralized disposal facilities. The model updates the landfill characteristics each year, calculating the total waste in place and the full time profile of waste disposal. This time profile was used to estimate the portion of the waste that contributes to methane emissions. Table I-1 shows the amount of waste landfilled each year and the total estimated waste in place contributing to methane emissions.

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[7] Emissions and sinks of biogenic carbon are accounted for under the Land-Use Change and Forestry sector.

Step 2: Estimate Landfill Methane Production

Emissions for each landfill were estimated by applying the emissions model (EPA 1993) to the landfill waste in place contributing to methane production. Total emission were then calculated as the sum of emissions from all landfills.

Step 3: Estimate Industrial Landfill Methane Production

Industrial landfills receive waste from factories, processing plants, and other manufacturing activities. Because there were no data available on methane generation at industrial landfills, the approach used was to assume that industrial methane production equaled about 7 percent of MSW landfill methane production (EPA 1993), as shown below in Table I-2.

Step 4: Estimate Methane Recovery

To estimate landfill gas (LFG) recovered per year, data on current and planned LFG recovery projects in the United States were obtained from Governmental Advisory Associates (GAA 1994). The GAA report, considered to be the most comprehensive source of information on gas recovery in the United States, has estimates for gas recovery in 1990 and 1992. Their data set showed that 1.20 and 1.44 teragrams (Tg) of methane were recovered nationally by municipal solid waste landfills in 1990 and 1992, respectively. In addition, a number of landfills were believed to recover and flare methane without energy recovery and were not included in the GAA database. To account for the amount of methane flared without energy recovery, the estimate of gas recovered was increased by 25 percent (EPA 1993). Therefore, net methane recovery from landfills was assumed to equal 1.50 Tg in 1990, and 1.80 Tg in 1992. The 1990 estimate of methane recovered was used for 1991 and the 1992 estimate was used for the period 1992 to 1996. EPA is currently reviewing more detailed information on LFG recovery projects and expects that the total recovery figure could be significantly higher.

Step 5: Estimate Methane Oxidation

As discussed above, a portion of the methane escaping from a landfill through its cover oxidizes in the top layer of the soil. The amount of oxidation that occurs is uncertain and depends upon the characteristics of the soil and the environment. For purposes of this analysis, it was assumed that 10 percent of the methane produced was oxidized in the soil.

Step 6: Estimate Total Methane Emissions

Total methane emissions were calculated by adding emissions from MSW and industrial waste, and subtracting methane recovered and oxidized, as shown in Table I-2.

Table I-1: Municipal Solid Waste (MSW) Contributing to Methane Emissions (Tg)

Description	1990	1991	1992	1993	1994	1995	1996
Total MSW Generated[a]	264	255	265	278	293	296	297
Percent of MSW Landfilled[a]	71%	76%	72%	71%	67%	63%	62%
Total MSW Landfilled	189	194	190	197	196	187	184
MSW Contributing to Emissions[b]	4,926	5,027	5,162	5,292	5,428	5,559	5,676

[a] Source: Biocycle (1997). The data, originally reported in short tons, are converted to metric tons.
[b] The EPA emissions model (EPA 1993) defines all waste younger than 30 years as contributing to methane emissions.

Table I-2: Methane Emissions from Landfills (Tg)

Activity	1990	1991	1992	1993	1994	1995	1996
MSW Generation	11.6	11.8	12.2	12.5	12.8	13.2	13.5
Large Landfills	4.53	4.62	4.76	4.91	5.11	5.29	5.45
Medium Landfills	5.79	5.91	6.07	6.23	6.36	6.53	6.62
Small Landfills	1.27	1.30	1.33	1.36	1.39	1.41	1.42
Industrial Generation	0.73	0.75	0.77	0.79	0.81	0.83	0.85
Potential Emissions	12.3	12.6	12.9	13.3	13.7	14.1	14.3
Recovery	(1.50)	(1.50)	(1.80)	(1.80)	(1.80)	(1.80)	(1.80)
Oxidation	(1.09)	(1.12)	(1.12)	(1.16)	(1.19)	(1.23)	(1.26)
Net Emissions	**9.82**	**10.0**	**10.1**	**10.4**	**10.8**	**11.1**	**11.4**

Note: Totals may not sum due to independent rounding.

Table I-3: Municipal Solid Waste Landfill Size Definitions (Tg)

Description	Waste in Place
Small Landfills	< 0.4
Medium Landfills	0.4 - 2.0
Large Landfills	> 2.0

Annex J

Global Warming Potentials

Table J-1: Global Warming Potentials and Atmospheric Lifetimes (years)

Gas	Atmospheric Lifetime	GWP[a]
Carbon dioxide (CO_2)	50-200	1
Methane (CH_4)[b]	12±3	21
Nitrous oxide (N_2O)	120	310
HFC-23	264	11,700
HFC-125	32.6	2,800
HFC-134a	14.6	1,300
HFC-143a	48.3	3,800
HFC-152a	1.5	140
HFC-227ea	36.5	2,900
HFC-236fa	209	6,300
HFC-4310mee	17.1	1,300
CF_4	50,000	6,500
C_2F_6	10,000	9,200
C_4F_{10}	2,600	7,000
C_6F_{14}	3,200	7,400
SF_6	3,200	23,900

Source: (IPCC 1996)

[a] 100 year time horizon

[b] The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Annex K
Ozone Depleting Substance Emissions

Ozone is present in both the stratosphere[8], where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere[9], where it is the main component of anthropogenic photochemical “smog”. Chlorofluorocarbons (CFCs) and other compounds that contain chlorine or bromine have been found to destroy ozone in the stratosphere, and are commonly referred to as ozone-depleting substances (ODSs). If left unchecked, ozone depletion could result in a dangerous increase of ultraviolet radiation reaching the earth’s surface. In 1987, nations around the world signed the *Montreal Protocol on Substances that Deplete the Ozone Layer*. This landmark agreement created an international framework for limiting, and ultimately eliminating, the use and emission of most ozone depleting substances, which are used in a variety of industrial applications, including refrigeration and air conditioning, foam blowing, fire extinguishing, aerosol propellants, sterilization, and solvent cleaning.

In the United States, the Clean Air Act Amendments of 1990 provide the legal instrument for implementation of the *Montreal Protocol* controls. The Clean Air Act classifies ozone depleting substances as either Class I or Class II, depending upon the ozone depletion potential (ODP) of the compound.[10] The production of CFCs, halons, carbon tetrachloride, and methyl chloroform, all Class I substances, has already ended in the United States. However, because stocks of these chemicals remain available and in use, they will continue to be emitted for many years from applications such as refrigeration and air conditioning equipment, fire extinguishing systems, and metered dose inhalers. As a result, emissions of Class I compounds will continue, in ever decreasing amounts, into the early part of the next century. Class II substances, which are comprised of hydrochlorofluorocarbons (HCFCs), are being phased-out at a later date because of their lower ozone depletion potentials. These compounds are serving as interim replacements for Class I compounds in many industrial applications. The use and emissions of HCFCs in the United States is anticipated to increase over the next several years. Under current controls, the production of all HCFCs in the United States will end by the year 2030.

In addition to contributing to ozone depletion, CFCs, halons, carbon tetrachloride, methyl chloroform, and HCFCs are also significant greenhouse gases. The total impact of ozone depleting substances on global warming is not clear, however, because ozone is also a greenhouse gas. The depletion of ozone in the stratosphere by ODSs has an indirect negative radiative forcing, while most ODSs have a positive direct radiative forcing effect. The IPCC has prepared both direct GWPs and net (i.e., combined direct and indirect effects) GWP ranges for some of the most common ozone depleting substances (IPCC 1996). Direct GWPs account for the direct global warming impact of the emitted gas. Net GWP ranges account for both the direct impact of the emitted gas and the indirect effects resulting from the destruction of ozone.

Although the IPCC emission inventory guidelines do not include reporting emissions of ozone depleting substances, the United States believes that no inventory is complete without the inclusion of these emissions. Emission estimates for several ozone depleting substances are provided in Table K-1.

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[8] The stratosphere is the layer from the top of the troposphere up to about 50 kilometers. Approximately 90 percent of atmospheric ozone lies within the stratosphere. The greatest concentration of ozone occurs in the middle of the stratosphere, in a region commonly called the ozone-layer.

[9] The troposphere is the layer from the ground up to about 11 kilometers near the poles and 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere, where humans live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for weather processes including most of the water vapor and clouds.

[10] Substances with an ozone depletion potential of 0.2 or greater are classified as Class I. All other substances that may deplete stratospheric ozone but which do not have an ODP of 0.2 or greater, are classified as Class II.

Table K-1: Emissions of Ozone Depleting Substances (Mg)

Compound	1990	1991	1992	1993	1994	1995	1996
Class I							
CFC-11	53,500	48,300	45,100	45,400	36,600	36,200	26,600
CFC-12	112,600	103,500	80,500	79,300	57,600	51,800	35,500
CFC-113	26,350	20,550	17,100	17,100	8,550	8,550	+
CFC-114	4,700	3,600	3,000	3,000	1,600	1,600	300
CFC-115	4,200	4,000	3,800	3,600	3,300	3,000	3,200
Carbon Tetrachloride	32,300	31,000	21,700	18,600	15,500	4,700	+
Methyl Chloroform	158,300	154,700	108,300	92,850	77,350	46,400	+
Halon-1211	1,000	1,100	1,000	1,100	1,000	1,100	1,100
Halon-1301	1,800	1,800	1,700	1,700	1,400	1,400	1,400
Class II							
HCFC-22	79,789	79,540	79,545	71,224	71,386	74,229	77,472
HCFC-123	+	+	285	570	844	1,094	1,335
HCFC-124	+	+	429	2,575	4,768	5,195	5,558
HCFC-141b	+	+	+	1,909	6,529	11,608	14,270
HCFC-142b	+	+	3,526	9,055	14,879	21,058	27,543
HCFC-225ca/cb	+	+	+	+	+	565	579

Source: EPA estimates
+ Does not exceed 10 Mg

Methodology and Data Sources

Emissions of ozone depleting substances were estimated using two simulation models: the Atmospheric and Health Effects Framework (AHEF) and EPA's Vintaging Model.

The Atmospheric and Health Effects Framework model contains estimates of U.S. domestic use of each of the ozone depleting substances. These estimates were based upon data that industry reports to EPA and other published material. The annual consumption of each compound was divided into various end-uses based upon historical trends and research into specific industrial applications. These end-uses include refrigerants, foam blowing agents, solvents, aerosol propellants, sterilants, and fire extinguishing agents.

With the exception of aerosols, solvents, and certain foam blowing agents, emissions of ozone depleting substances are not instantaneous, but instead occur gradually over time (i.e., emissions in a given year are the result of both ODS use in that year and use in previous years). Each end-use has a certain release profile, which gives the percentage of the compound that is released to the atmosphere each year until all releases have occurred. In refrigeration equipment, for example, the initial charge is released slowly over the lifetime of the equipment, which could be 20 or more years. In addition, not all of the refrigerant is ultimately emitted—some will be recovered when the equipment is retired from operation.

The AHEF model was used to estimate emissions of ODSs that were in use prior to the controls implemented under the *Montreal Protocol*. This included CFCs, halons, carbon tetrachloride, methyl chloroform, and HCFC-22. Certain HCFCs, such as HCFC-123, HCFC-124, HCFC-141b, HCFC-142b, HCFC-225ca and HCFC-225cb, have also entered the market as interim substitutes for ODSs. Emissions estimates for these compounds were taken from EPA's Vintaging Model.

The Vintaging Model was used to estimate the use and emissions of various ODS substitutes, including HCFCs. The name refers to the fact that the model tracks the use and emissions of various compounds by the annual "vintages" of new equipment that enter service in each end-use. The Vintaging Model is a "bottom-up" model. Information was collected regarding the sales of equipment that use ODS substitutes and the amount of the chemical required by each unit of equipment. Emissions for each end-use were estimated by applying annual leak rates and release profiles, as in the AHEF. By aggregating the data for more than 40 different end-uses, the model produces estimates of annual use and emissions of each compound.

Uncertainties

Uncertainties exist with regard to the levels of chemical production, equipment sales, equipment characteristics, and end-use emissions profiles that are used by these models.

Annex L
Sulfur Dioxide Emissions

Sulfur dioxide (SO_2) emitted into the atmosphere through natural and anthropogenic processes affects the Earth's radiative budget through photochemical transformation into sulfate aerosols that can (1) scatter sunlight back to space, thereby reducing the radiation reaching the Earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., stratospheric ozone, by providing surfaces for heterogeneous chemical reactions). The overall effect of SO_2 derived aerosols on radiative forcing is believed to be negative (IPCC 1996). However, because SO_2 is short-lived and unevenly distributed through the atmosphere, its radiative forcing impacts are highly uncertain. Sulfur dioxide emissions have been provided below in Table L-1.

The major source of SO_2 emissions in the United States was the burning of sulfur containing fuels, mainly coal. Metal smelting and other industrial processes also released significant quantities of SO_2. As a result, the largest contributors to overall U.S. emissions of SO_2 were electric utilities, accounting for 66 percent in 1996 (see Table L-2). Coal combustion accounted for approximately 96 percent of SO_2 emissions from electric utilities in the same year. The second largest source was industrial fuel combustion, which produced 18 percent of 1996 SO_2 emissions. Overall, sulfur dioxide emissions in the United States decreased by 19 percent from 1990 to 1996. Eighty-two percent of this decline came from reductions from electric utilities, primarily due to increased consumption of low sulfur coal from surface mines in western states.

Sulfur dioxide is important for reasons other than its effect on radiative forcing. It is a major contributor to the formation of urban smog and acid rain. As a contributor to urban smog, high concentrations of SO_2 can cause significant increases in acute and chronic respiratory diseases. In addition, once SO_2 is emitted, it is chemically transformed in the atmosphere and returns to earth as the primary contributor to acid deposition, or acid rain. Acid rain has been found to accelerate the decay of building materials and paints, as well as cause the acidification of lakes and streams and damage trees. As a result of these harmful effects, the United States has regulated the emissions of SO_2 under the Clean Air Act. The EPA has also developed a strategy to control these emissions via four programs: (1) the National Ambient Air Quality Standards program,[11] (2) New Source Performance Standards,[12] (3) the New Source Review/Prevention of Significant Deterioration Program,[13] and (4) the sulfur dioxide allowance program.[14]

[11] [42 U.S.C § 7409, CAA § 109]
[12] [42 U.S.C § 7411, CAA § 111]
[13] [42 U.S.C § 7473, CAA § 163]
[14] [42 U.S.C § 7651, CAA § 401]

Table L-1: Emissions of SO_2 (Gg)

Sector/Source	1990	1991	1992	1993	1994	1995	1996
Energy	**20,034**	**19,524**	**19,327**	**18,973**	**18,444**	**16,006**	**16,174**
Stationary Sources	18,407	17,959	17,684	17,459	17,134	14,724	15,228
Mobile Sources	1,237	1,222	1,267	1,166	965	947	612
Oil and Gas Activities	390	343	377	347	344	334	334
Industrial Processes	**1,306**	**1,187**	**1,186**	**1,159**	**1,135**	**1,116**	**1,122**
Chemical Manufacturing	269	254	252	244	249	260	260
Metals Processing	658	555	558	547	510	481	481
Storage and Transport	6	9	8	4	1	2	2
Other Industrial Processes	362	360	360	355	361	365	371
Miscellaneous*	11	10	9	8	13	8	8
Solvent Use	**+**	**+**	**+**	**1**	**1**	**1**	**1**
Degreasing	+	+	+	+	+	+	+
Graphic Arts	+	+	+	+	+	+	+
Dry Cleaning	NA	NA	+	NA	+	+	+
Surface Coating	+	+	+	+	+	+	+
Other Industrial	+	+	+	+	+	+	+
Non-industrial	NA	NA	NA	NA	NA	NA	NA
Agriculture	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
Waste	**38**	**40**	**40**	**65**	**54**	**43**	**43**
Waste Combustion	38	39	39	56	48	42	42
Landfills	+	+	+	+	+	+	+
Wastewater Treatment	+	+	+	+	+	1	1
Miscellaneous Waste	+	1	1	8	5	+	+
Total	**21,379**	**20,752**	**20,554**	**20,196**	**19,633**	**17,165**	**17,339**

Source: (EPA 1997)
* Miscellaneous includes other combustion and fugitive dust categories.
+ Does not exceed 0.5 Gg
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Table L-2: Emissions of SO_2 from Electric Utilities (Gg)

Fuel Type	1990	1991	1992	1993	1994	1995	1996
Coal	13,807	13,687	13,448	13,179	12,985	10,526	10,990
Oil	580	591	495	555	474	375	373
Gas	1	1	1	1	1	8	19
Misc. Internal Combustion	45	41	42	45	48	50	52
Total	**14,432**	**14,320**	**13,986**	**13,779**	**13,507**	**10,959**	**11,434**

Source: (EPA 1997)
Note: Totals may not sum due to independent rounding.

Annex M
Complete List of Sources

Sector/Source	Gas(es)
Energy	
Carbon Dioxide Emissions from Fossil Fuel Combustion	CO_2
Stationary Source Fossil Fuel Combustion (excluding CO_2)	CH_4, N_2O, CO, NO_x, NMVOC
Mobile Source Fossil Fuel Combustion (excluding CO_2)	CH_4, N_2O, CO, NO_x, NMVOC
Coal Mining	CH_4
Natural Gas Systems	CH_4
Petroleum Systems	CH_4
Natural Gas Flaring and Criteria Pollutant Emissions from Oil and Gas Activities	CO_2, CO, NO_x, NMVOC
Wood Biomass and Ethanol Consumption	CO_2
Industrial Processes	
Cement Manufacture	CO_2
Lime Manufacture	CO_2
Limestone and Dolomite Use	CO_2
Soda Ash Manufacture and Consumption	CO_2
Carbon Dioxide Manufacture	CO_2
Iron and Steel Production	CO_2
Ammonia Manufacture	CO_2
Ferroalloy Production	CO_2
Petrochemical Production	CH_4
Silicon Carbide Production	CH_4
Adipic Acid Production	N_2O
Nitric Acid Production	N_2O
Substitution of Ozone Depleting Substances	HFCs, PFCs[a]
Aluminum Production	CF_4, C_2F_6
HCFC-22 Production	HFC-23
Semiconductor Manufacture	HFCs, PFCs, SF_6[b]
Electrical Transmission and Distribution	SF_6
Magnesium Production and Processing	SF_6
Industrial Sources of Criteria Pollutants	CO, NO_x, NMVOC
Solvent Use	CO, NO_x, NMVOC
Agriculture	
Enteric Fermentation	CH_4
Manure Management	CH_4, N_2O
Rice Cultivation	CH_4
Agricultural Soil Management	N_2O
Agricultural Residue Burning	CH_4, N_2O, CO, NO_x
Land-Use Change and Forestry	
Changes in Forest Carbon Stocks	CO_2
Changes in Non-Forest Soil Carbon Stocks	CO_2
Waste	
Landfills	CH_4
Wastewater Treatment	CH_4
Human Sewage	N_2O
Waste Combustion	N_2O
Waste Sources of Criteria Pollutants	CO, NO_x, NMVOC

[a] In 1996, included HFC-23, HFC-125, HFC-134a, HFC-143a, HFC-152a, HFC-227ea, HFC-236fa, HFC-4310mee, C_4F_{10}, C_6F_{14}, PFC/PFPEs
[b] Included such gases as HFC-23, CF_4, C_2F_6, SF_6

Annex N
IPCC Reporting Tables

This annex contains a series of tables which summarize the emissions and activity data discussed in the body of this report. The data in these tables conform with guidelines established by the IPCC (IPCC/UNEP/OECD/IEA 1997; vol. 1) for consistent international reporting of greenhouse gas emissions inventories. The format of these tables does not always correspond directly with the calculations discussed in the body of the report. In these instances, the data have been reorganized to conform to IPCC reporting guidelines. As a result, slight differences may exist between the figures presented in the IPCC tables and those in the body of the report. These differences are merely an artifact of variations in reporting structures; total U.S. emissions are unaffected.

Title of Inventory	*Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1996*
Contact Name	Wiley Barbour
Title	
Organisation	U.S. Environmental Protection Agency
Address	Climate Policy and Programs Division (2175) 401 M Street, SW Washington, DC 20460
Phone	(202) 260-6972
Fax	(202) 260-6405
E-Mail	barbour.wiley@epamail.epa.gov
Is uncertainty addressed?	Yes
Related documents filed with IPCC	Yes

IPCC Table 1: Sectoral Report for Energy (1996)

Sectoral Report for National Greenhouse Gas Inventories (Gg)							
Greenhouse Gas Source and Sink Categories	**CO_2 [a]**	**CH_4**	**N_2O**	**NOx**	**CO**	**NMVOC**	**SO_2**
Total Energy	**5,330,574**	**10,188.5**	**242.92**	**20,123**	**67,596**	**8,470**	**16,173**
A Fuel Combustion Activities (Reference)	5,317,701						
A Fuel Combustion Activities (Sectoral)	5,317,843	667.1	242.92	20,024	67,280	8,014	15,839
1 Electric Utilities	1,895,156	23.3	26.13	5,991	341	41	11,434
Petroleum	57,236	-	-	-	-	-	-
Gas	147,859	-	-	-	-	-	-
Coal	1,689,925	-	-	-	-	-	-
Geothermal	135	-	-	-	-	-	-
2 Industry	1,125,708	141.6	16.56	2,794	972	188	3,084
Petroleum	383,708	-	-	-	-	-	-
Gas	524,213	-	-	-	-	-	-
Coal	217,787	-	-	-	-	-	-
3 Transport	1,631,090	238.4	195.44	10,656	61,931	7,048	612
Petroleum	1,592,519	-	-	-	-	-	-
Gas	38,570	-	-	-	-	-	-
Coal	0	-	-	-	-	-	-
4 Commercial	237,504	38.2	1.08	336	219	21	IE
Petroleum	56,184	-	-	-	-	-	
Gas	173,678	-	-	-	-	-	
Coal	7,642	-	-	-	-	-	
5 Residential	388,656	225.6	3.71	654	3,817	715	164
Petroleum	99,796	-	-	-	-	-	-
Gas	283,795	-	-	-	-	-	-
Coal	5,065	-	-	-	-	-	-
6 Agriculture / Forestry	IE	IE	IE	IE	IE	IE	IE
Petroleum							
Gas							
Coal							
7 Territories	39,730	NE	NE	NE	NE	NE	NE
Petroleum	38,794						
Gas							
Coal	936						
B Fugitive Emissions from Fuels	12,730	9,521.3	NE	100	316	456	334
1 Solid Fuels	NE	3,301.0	NE	NE	NE	NE	NE
a Coal Mining		3,301.0					
2 Petroleum and Natural Gas	12,730	6,220.3	NE	100	316	456	334
a Petroleum		270.6		-	-	-	-
b Natural Gas		5,949.7		-	-	-	-
c Venting and Flaring	12,730			-	-	-	-
Memo Items*:							
International Bunkers	82,443	NE	NE	IE	IE	IE	IE
Aviation	22,096						
Marine	60,346						
CO_2 Emissions from Biomass [b]	200,108	IE	IE	IE	IE	IE	IE
Wood	194,963						
Ethanol	5,145						

*Not included in energy totals
Note: Totals may not equal sum of components due to independent rounding.
"-" = Value is not estimated separately, but included in an aggregate figure.
NE = Not estimated
IE = Estimated but included elsewhere
[a] For CO_2 calculations a detailed bottom-up approach was implemented using activity data disaggregated by sector and fuel type.
[b] CO_2 emissions estimates from biomass consumption are from commercial, industrial, residential, transportation, and electric power production applications. Estimates of non-CO_2 emissions from these sources were calculated via U.S. EPA methodologies and are incorporated in sectoral estimates in section A.

IPCC Table 2a: Sectoral Report for Industrial Processes (1996)

	Sectoral Report for National Greenhouse Gas Inventories (Gg)									
Greenhouse Gas Source and Sink Categories	**CO_2**	**CH_4**	**N_2O**	**NOx**	**CO**	**NMVOC**	**SO_2**	**HFCs [b]**	**PFCs [b]**	**SF_6**
Total Industrial Processes	63,309	73.9	108.71	820	5,338	1,970	1,122	[b]	[b]	1.5342
A Mineral Products	62,169	NE	NE	IE	IE	IE	IE	NE	NE	NE
1 Cement Production	37,061									
2 Lime Production	14,092									
3 Limestone and Dolomite Use	6,743									
4 Soda Ash Production and Use	4,273									
5 Asphalt Roofing	NE			IE	IE	IE	IE			
6 Other	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
B Chemical Industry	1,140	73.9	108.71	144	1,110	377	260	IE	IE	IE
1 Ammonia Production	23,138 [a]			-	-	-	-			
2 Nitric Acid Production			45.38	-	-	-	-			
3 Adipic Acid Production			63.32	-	-	-	-			
4 Silicon Carbide Production		0.9		-	-	-	-			
5 Carbon Dioxide Production	1,140			-	-	-	-			
6 Petrochemical Production		73.0		-	-	-	-			
C Metal Production	IE	NE	NE	89	2,157	64	481	NE	[b]	0.4603
1 Iron and Steel Production	79,040 [a]			-	-	-	-			
2 Ferroalloys Production	1,695 [a]			-	-	-	-			
3 Aluminum Production	5258 [a]			-	-	-	-		[b]	
4 SF_6 Used in Aluminum and Magnesium Foundries				-	-	-	-			0.4603
D Other Production	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
E Production of Halocarbons and SF_6	NE	NE	NE	NE	NE	NE	NE	IE [b]	IE [b]	IE
1 Byproduct Emissions								IE [b]		
2 Fugitive Emissions										
3 Other										
F Consumption of Halocarbons and SF_6	NE	NE	NE	NE	NE	NE	NE	IE [b]	IE [b]	1.0739
1 Refrigeration and Air Conditioning Equipment								-	-	
2 Foam Blowing								-	-	
3 Fire Extinguishers								-	-	
4 Aerosols								-	-	
5 Solvents								-	-	
6 Electrical Transmission and Distribution								-	-	1.0739
G Other	IE	IE	IE	587	2,071	1,529	381	NO	NO	NO
1 Storage and Transport				5	23	889	2			
2 Other Industrial Processes				366	576	391	371			
3 Miscellaneous				216	1,472	249	8			

Note: Totals may not equal sum of components due to independent rounding.
"-" = Value is not estimated separately, but included in an aggregate figure.
NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
NA = Not applicable

[a] CO_2 emissions from aluminum, ammonia, ferroalloy, and iron & steel production are included in this table for informational purposes, but are not included in the national total in order to prevent double counting these emissions, which are included under non-fuel industrial uses under the Energy sector.
[b] Emissions of HFCs and PFCs are documented by gas in Table 2b.
[c] Includes cooling towers, fugitive dust, health services

IPCC Table 2b: Detailed Emissions of HFCs (1996)

	(MMTCE)	Sectoral Report for National Greenhouse Gas Inventories(Gg)							
Greenhouse Gas Source and Sink Categories	**Unspecified***	**HFC-23**	**HFC-125**	**HFC-134a**	**HFC-143a**	**HFC-152a**	**HFC-227ea**	**HFC-236fa**	**HFC-4310mee**
Total HFCs and PFCs	**1.4**	**2.690**	**3.172**	**13.605**	**0.226**	**1.08**	**2.063**	**0.079**	**1.030**
A Substitution of Ozone Depleting Substances		0.026	3.172	13.605	0.226	1.08	2.063	0.079	1.030
B Aluminum Production		NO	NO	NO	NO	NO	NO	NO	NO
C HCFC-22 Production		2.664	NO	NO	NO	NO	NO	NO	NO
D Semiconductor Manufacture	1.4	IE	NO	NO	NO	NO	NO	NO	NO

*Includes gases such as HFC-23, CF_4, C_2F_6, SF_6, and C_3F_8
IE = Estimated but included elsewhere
NO = Not known to be occurring

IPCC Table 2c: Detailed Emissions of PFCs (1996)

	Sectoral Report for National Greenhouse Gas Inventories (Gg)				
Greenhouse Gas Source and Sink Categories	**CF_4**	**C_2F_6**	**C_4F_{10}**	**C_6F_{14}**	**PFC/PFPEs [a]**
Total HFCs and PFCs	**1.434**	**0.143**	**0.064**	**0.006**	**0.990**
A Substitution of Ozone Depleting Substances	NO	NO	0.064	0.006	0.990
B Aluminum Production	1.434	0.143	NO	NO	NO
C HCFC-22 Production	NO	NO	NO	NO	NO
D Semiconductor Manufacture	IE	IE	NO	NO	NO

IE = Estimated but included elsewhere
NO = Not known to be occurring
[a] PFC/PFPEs are a proxy for many diverse PFCs and perfluoropolyethers (PFPEs) that are employed in solvent applications. The GWP and atmospheric lifetime of this aggregate category is based upon that of C_6F_{14}.

IPCC Table 3: Sectoral Report for Solvent and Other Product Use (1996)

	Sectoral Report for National Greenhouse Gas Inventories (Gg)			
Greenhouse Gas Source and Sink Categories	**NOx**	**CO**	**NMVOC**	**SO_2**
Total Solvent and Other Product Use	**3**	**5**	**5,691**	**1**
A Degreasing	[a]	[a]	599	[a]
B Dry Cleaning	[a]	1	172	[a]
C Graphic Arts	1	[a]	353	[a]
D Surface Coating (including paint)	2	1	2,613	[a]
E Other Industrial	[a]	3	48	[a]
F Non-Industrial	[a]	[a]	1,905	NO

[a] Less than 0.5 Gg

IPCC Table 4: Sectoral Report for Agriculture (1996)

	Sectoral Report for National Greenhouse Gas Inventories (Gg)						
Greenhouse Gas Source and Sink Categories	**CO_2**	**CH_4**	**N_2O**	**NOx**	**CO**	**NMVOC**	**SO_2**
Total Agriculture	**NE**	**9,381.5**	**847.94**	**34**	**783**	**NE**	**NE**
A Enteric Fermentation	NE	6,023.0	NE	NE	NE		
1 Dairy Cattle		1,456.0					
2 Beef Cattle		4,294.0					
3 Sheep		68.0					

4 Goats		12.0					
5 Horses, Mules and Asses		108.0					
6 Swine		85.0					
B Manure Management	NE	2,889.9	34.95	NE	NE		
1 Dairy Cattle		786.6	0.84				
2 Beef Cattle		226.1	14.46				
3 Sheep		2.8	0.27				
4 Goats		0.9	0.05				
5 Horses, Mules and Asses		30.8	0.59				
6 Swine		1,541.3	0.76				
7 Poultry		301.5	17.97				
C Rice Cultivation	NE	431.3	NE	NE	NE		
1 Irrigated		431.3					
2 Rainfed							
3 Deepwater							
D Agricultural Soils	NE	NE	811.56	NE	NE		
1 Direct Emission from Agricultural Cropping Practices			442.32				
2 Direct Emissions from Animal Production			128.21				
3 Indirect Emissions from Nitrogen Applied to Agricultural Soils			241.03				
E Prescribed Burning of Savannas	NE	NE	NE	NE	NE		
F Field Burning of Agricultural Residues	NE	37.3	1.42	34	783		
1 Cereals		27.5	0.67	16	578		
2 Pulse		8.7	0.74	17	183		
3 Tuber and Root		0.1	0.01	0	2		
4 Sugar Cane		0.9	0.01	0	19		

Note: Totals may not equal sum of components due to independent rounding.
NE = Not estimated

IPCC Table 5: Sectoral Report for Land-Use Change and Forestry (1996)

Sectoral Report for National Greenhouse Gas Inventories (Gg)						
Greenhouse Gas Source and Sink Categories	**CO_2 Emissions**	**CO_2 Removals**	**CH_4**	**N_2O**	**NOx**	**CO**
Total Land-Use Change and Forestry		**-764,683**	**NE**	**NE**	**NE**	**NE**
A Changes in Forest and Other Woody Biomass Stocks		-311,667				
1 Forest Trees, Understory, Floor		-311,667				
B Forest and Grassland Conversion		NO				
C Abandonment of Managed Lands		NO				
D CO_2 Emissions and Removals from Soil		-316,250				
1 Forest Soils		-316,250				
2 Non-Forest Soils		NE				
E Other		-136,767				
1 Landfilled Wood Carbon Flux		-71,243				
2 Wood Product Flux		-65,523				

NE = Not estimated
NO = Not known to be occurring

IPCC Table 6: Sectoral Report for Waste (1996)

Sectoral Report for National Greenhouse Gas Inventories (Gg)							
Greenhouse Gas Source and Sink Categories	**CO_2**	**CH_4**	**N_2O**	**NOx**	**CO**	**NMVOC**	**SO_2**
Total Waste	**IE**	**11,532**	**28**	**87**	**1,019**	**368**	**43**
A Solid Waste Disposal on Land	IE	11,372	NE	1	2	19	[a]
1 Managed Waste Disposal		11,372		1	2	19	[a]
B Wastewater Handling	NE	161	27	[a]	[a]	58	1
1 Domestic		161	NE	[a]	[a]	47	-
2 Industrial		NE	NE	[a]	[a]	11	-
3 Human Sewage		-	27	-			
C Waste Incineration	IE	NE	1	85	1,016	218	42
1 Waste Incineration			1	49	402	50	32
2 Open Burning				36	614	169	10
D Other	NE	NE	NE	1	1	73	[a]
1 Treatment Storage and Disposal Facility						41	-
2 Scrap and Waste Materials/Leaking Underground Storage Tanks				1	1	32	-

"-" = Value is not estimated separately, but included in an aggregate figure.
[a] Less than 0.5 Gg
NE = Not estimated
IE = Estimated but included elsewhere

IPCC Table 7 A: Summary Report for National Greenhouse Gas Inventories (1996)

Summary Report for National Greenhouse Gas Inventories (Gg)											
Greenhouse Gas Source and Sink Categories	**CO_2 Emissions**	**CO_2 Removals**	**CH_4**	**N_2O**	**NO_x**	**CO**	**NMVOC**	**SO_2**	**HFCs**	**PFCs**	**SF_6**
Total National Emissions and Removals	**5,393,883**	**-764,683**	**31,176.1**	**1,227.11**	**21,067**	**74,741**	**16,499**	**17,339**	**[b]**	**[b]**	**1.5342**
1 Energy	5,330,574		10,188.5	242.92	20,123	67,596	8,470	16,173	NO	NO	NO
A Fuel Combustion Activities (Sectoral)	5,317,843		667.1	242.92	20,024	67,280	8,014	15,839			
1 Electric Utilities	1,895,156		23.3	26.13	5,473	341	41	11,434			
2 Industry	1,125,708		141.6	16.56	2,875	972	188	3,084			

3 Transport	1,631,090		238.4	195.44	10,656	61,931	7,048	612			
4 Commercial	237,504		38.2	1.08	336	219	21	546			
5 Residential	388,656		225.6	3.71	654	3,817	715	164			
6 Agriculture / Forestry	IE		IE	IE	IE	IE	IE	IE			
7 Territories	39,730		NE	NE	NE	NE	NE	NE			
B Fugitive Emissions from Fuels	12,730		9,521.3		100	316	456	334			
1 Solid Fuels	NE		3,301.0	NE	NE	NE	NE	NE			
2 Petroleum and Natural Gas	12,730		6,220.3	NE	100	316	456	334			
2 Industrial Processes	63,309		73.9	108.71	820	5,338	1,970	1,122	[b]	[b]	1.5342
A Mineral Products	62,169		NE	NE	IE	IE	IE	IE	NE	NE	NE
B Chemical Industry	1,140		73.9	108.71	144	1,110	377	260	IE	IE	IE
C Metal Production	IE		NE	NE	89	2,157	64	481	NE	[b]	0.4603
D Other Production	NA		NA	NA	NA	NA	NA	NA	NA	NA	NA
E Production of Halocarbons and SF_6	NE		NE	NE	NE	NE	NE	NE	IE [b]	IE [b]	IE
F Consumption of Halocarbons and SF_6	NE		NE	NE	NE	NE	NE	NE	IE [b]	IE [b]	1.0739
G Other	IE		IE	IE	587	2,071	1,529	381	NO	NO	NO
3 Solvent and Other Product Use	NE		NE	NE	3	5	5,691	1	NO	NO	NO

*Not included in energy totals
Note: Totals may not sum due to independent rounding.
NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
[a] CO_2 emissions estimates from biomass consumption are from commercial, industrial, residential, transportation, and electric power production applications. They are provided for informational purposes only and are not included in national totals. Estimates of non-CO_2 emissions from these sources were calculated via U.S. EPA methodologies and are incorporated in sectoral estimates in section 1A.
[b] Totaled by gas in Table 2b

IPCC Table 7 A (continued): Summary Report for National Greenhouse Gas Inventories (1996)

	Summary Report for National Greenhouse Gas Inventories (Gg)										
Greenhouse Gas Source and Sink Categories	**CO_2 Emissions**	**CO_2 Removals**	**CH_4**	**N_2O**	**NO_x**	**CO**	**NMVOC**	**SO_2**	**HFCs**	**PFCs**	**SF_6**
4 Agriculture	NE		9,381.5	847.94	34	783	NE	NE	NO	NO	NO
A Enteric Fermentation	NE		6,023.0	NE	NE	NE					
B Manure Management	NE		2,889.9	34.95	NE	NE					
C Rice Cultivation	NE		431.3	NE	NE	NE					
D Agricultural Soils	NE		NE	811.56	NE	NE					
E Prescribed Burning of Savannas	NO		NO	NO	NO	NO					
F Field Burning of Agricultural Residues	NE		37.3	1.42	34	783					
5 Land-Use Change & Forestry		-764,683	NE	NE	NE	NE	NE	NE	NO	NO	NO
A Changes in Forest and Other Woody Biomass Stocks		-311,667									
B Forest and Grassland Conversion		NO									
C Abandonment of Managed Lands		NO									
D CO_2 Emissions and Removals from Soil		-316,250									
E Other		-136,767									
6 Waste	IE		11,532.3	27.55	87	1,019	368	43	NO	NO	NO
A Solid Waste Disposal on Land	IE		11,371.7	NE	1	2	19	0			
B Wastewater Handling	NE		160.6	26.66	0	0	58	1			
C Waste Incineration	IE		NE	0.89	85	1,016	218	42			
D Other	NE		NE	NE	1	1	73	0			
Memo Items*:											
International Bunkers	82,443		NE	NE	IE	IE	IE	IE	NO	NO	NO
Aviation	22,096										
Marine	60,346										
CO_2 Emissions from Biomass [a]	200,108		IE	IE	IE	IE	IE	IE	NO	NO	NO

*Not included in energy totals
Note: Totals may not sum due to independent rounding.
NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
[a] CO_2 emissions estimates from biomass consumption are from commercial, industrial, residential, transportation, and electric power production applications. They are provided for informational purposes only and are not included in national totals. Estimates of non-CO_2 emissions from these sources were calculated via U.S. EPA methodologies and are incorporated in sectoral estimates in section 1A.
[b] Totaled by gas in Table 2b

IPCC Table 7B: Short Summary Report for National Greenhouse Gas Inventories (1996)

Summary Report for National Greenhouse Gas Inventories (Gg)											
Greenhouse Gas Source and Sink Categories	**CO_2 Emissions**	**CO_2 Removals**	**CH_4**	**N_2O**	**NOx**	**CO**	**NMVOC**	**SO_2**	**HFCs**	**PFCs**	**SF_6**
Total National Emissions and Removals	**5,393,883**	**-764,683**	**31,176.1**	**1,227.11**	**21,067**	**74,741**	**16,499**	**17,339**	**[b]**	**[b]**	**1.5342**
1 Energy (Reference Approach)	5,317,701										
1 Energy (Sectoral Approach)	5,330,574		10,188.5	242.92	20,123	67,596	8,470	16,173	NO	NO	NO
A Fuel Combustion Activities	5,317,843		667.1	242.92	20,024	67,280	8,014	15,839			
B Fugitive Emissions from Fuels	12,730		9,521.3	NE	100	316	456	334			
2 Industrial Processes	63,309		73.9	108.71	820	5,338	1,970	1,122	[b]	[b]	1.5342
3 Solvent and Other Product Use	NE		NE	NE	3	5	5,691	1	NO	NO	NO
4 Agriculture	NE		9,381.5	847.94	34	783	NE	NE	NO	NO	NO
5 Land-Use Change & Forestry		-764,683	NE	NE	NE	NE	NE	NE	NO	NO	NO
6 Waste	IE		11,532.3	27.55	87	1,019	368	43	NO	NO	NO
Memo Items*:											
International Bunkers	82,443		NE	NE	IE	IE	IE	IE	NO	NO	NO
Aviation	22,096										
Marine	60,346										
CO_2 Emissions from Biomass [a]	200,108		IE	IE	IE	IE	IE	IE	NO	NO	NO

*Not included in energy totals
Note: Totals may not sum due to independent rounding.
NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
[a] CO_2 emissions estimates from biomass consumption are from commercial, industrial, residential, transportation, and electric power production applications. They are provided for informational purposes only and are not included in national totals. Estimates of non-CO_2 emissions from these sources were calculated via U.S. EPA methodologies and are incorporated in sectoral estimates in section 1A.
[b] Totaled by gas in Table 2b

IPCC Table 8A (part I): Overview Table for National Greenhouse Gas Inventories (1996)

Greenhouse Gas Source and Sink Categories	CO_2		CH_4		N_2O		NOx		CO		NMVOC	
	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality
Total National Emissions and Removals												
1 Energy												
A Fuel Combustion Activities (Reference)	ALL	H	NE		NE		NE		NE		NE	
A Fuel Combustion Activities (Sectoral)												
1 Electric Utilities	ALL	H	ALL	M	ALL	M	ALL	H	ALL	H	ALL	H
2 Industry	ALL	H	ALL	M	ALL	M	ALL	H	ALL	H	ALL	H
3 Transport	ALL	H	ALL	M	PART [b]	M	ALL	H	ALL	H	ALL	H
4 Commercial	ALL	H	ALL	M	ALL	M	ALL	H	ALL	H	ALL	H
5 Residential	ALL	H	ALL	M	ALL	M	ALL	H	ALL	H	ALL	H
6 Agriculture / Forestry	IE		IE		IE		IE		IE		IE	
7 Territories	ALL	H	NE		NE		NE		NE		NE	
B Fugitive Emissions from Fuels												
1 Solid Fuels	NE		ALL	M	NE		NE		NE		NE	
2 Petroleum and Natural Gas	PART [c]	M	ALL	M	NE		ALL	H	ALL	H	ALL	H
2 Industrial Processes												
A Mineral Products	ALL	H	NE		NE		IE		IE		IE	
B Chemical Industry	ALL	M	ALL	M	ALL	H	ALL	H	ALL	H	ALL	H
C Metal Production	IE		NE		NE		ALL	H	ALL	H	ALL	H
D Other Production	NA		NA		NA		NA		NA		NA	
E Production of Halocarbons and SF_6	NO		NO		NO		NO		NO		NO	
F Consumption of Halocarbons and SF_6	NO		NO		NO		NO		NO		NO	
G Other [f]	IE		IE		IE		ALL	H	ALL	H	ALL	H
3 Solvent and Other Product Use	NE		NE		NE		ALL	H	ALL	H	ALL	H

NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
NA = Not applicable
PART = Partly estimated
ALL = Full estimate of all possible sources

Quality:
H = High Confidence in Estimation
M = Medium Confidence in Estimation
L = Low Confidence in Estimation

Documentation:
H = High (all background information included)
M = Medium (some background information included)
L = Low (only emission estimates included)

Disaggregation:
1 = Total emissions estimated
2 = Sectoral split
3 = Subsectoral split

[a] Non-forest soils are not included in this estimate.
[b] Estimate does not include nitrous oxide emissions from jet aircraft.
[c] Estimate excludes geologic carbon dioxide deposits released during petroleum and natural gas production.
[d] Estimate does not include emissions from industrial wastewater.
[e] Includes emissions from human sewage only
[f] From storage and transport; other industrial processes; and cooling towers, fugitive dust, and health services
[g] From landfilled wood and wood product flux
[h] From treatment, storage and disposal facilities: scrap and waste materials; and underground storage tanks

IPCC Table 8A (part II): Overview Table for National Greenhouse Gas Inventories (1996)

Greenhouse Gas Source and Sink Categories	CO_2		CH_4		N_2O		NOx		CO		NMVOC	
	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality
4 Agriculture												
A Enteric Fermentation	NE		ALL	M	NE		NE		NE		NE	
B Manure Management	NE		ALL	M	ALL	M	NE		NE		NE	
C Rice Cultivation	NE		ALL	M	NE		NE		NE		NE	
D Agricultural Soils	NE		NE		ALL	M	NE		NE		NE	
E Prescribed Burning of Savannas	NE		NE		NE		NE		NE		NE	
F Field Burning of Agricultural Residues	NE		ALL	M	ALL	M	ALL	M	ALL	M	NE	
5 Land-Use Change & Forestry												

A Changes in Forest and Other Woody Biomass Stocks	ALL	M	NE		NE		NE		NE		NE	
B Forest and Grassland Conversion	NO		NE		NE		NE		NE		NE	
C Abandonment of Managed Lands	NO		NE		NE		NE		NE		NE	
D CO_2 Emissions and Removals from Soil	PART [a]	L	NE		NE		NE		NE		NE	
E Other [g]	ALL	M	NE		NE		NE		NE		NE	
6 Waste												
A Solid Waste Disposal on Land	IE		ALL	H	NE		ALL	H	ALL	H	ALL	H
B Wastewater Handling	NE		PART [d]	M	PART [e]		ALL	H	ALL	H	ALL	H
C Waste Incineration	IE		NE		ALL	M	ALL	H	ALL	H	ALL	H
D Other [h]	NE		NE		NE	M	ALL	H	ALL	H	ALL	H
Memo Items:												
International Bunkers												
Aviation	ALL	M	NE		NE		IE		IE		IE	
Marine	ALL	M	NE		NE		IE		IE		IE	
CO_2 Emissions from Biomass [a]	ALL	M	IE		IE		IE		IE		IE	

NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
NA = Not applicable
PART = Partly estimated
ALL = Full estimate of all possible sources

Quality:
H = High Confidence in Estimation
M = Medium Confidence in Estimation
L = Low Confidence in Estimation

Documentation:
H = High (all background information included)
M = Medium (some background information included)
L = Low (only emission estimates included)

Disaggregation:
1 = Total emissions estimated
2 = Sectoral split
3 = Subsectoral split

[a] Non-forest soils are not included in this estimate.
[b] Estimate does not include nitrous oxide emissions from jet aircraft.
[c] Estimate excludes geologic carbon dioxide deposits released during petroleum and natural gas production.
[d] Estimate does not include emissions from industrial wastewater.
[e] Includes emissions from human sewage only
[f] From storage and transport; other industrial processes; and cooling towers, fugitive dust, and health services
[g] From landfilled wood and wood product flux
[h] From treatment, storage and disposal facilities: scrap and waste materials; and underground storage tanks

IPCC Table 8A (part III): Overview Table for National Greenhouse Gas Inventories (1996)

Greenhouse Gas Source and Sink Categories	SO_2		HFCs		PFCs		SF_6		Documentation	Disaggregation	Footnotes
	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality			
Total National Emissions and Removals											
1 Energy											
A Fuel Combustion Activities (Reference)	NE		NE		NE		NE		H	3	
A Fuel Combustion Activities (Sectoral)									H	3	
1 Electric Utilities	ALL	H	NO		NO		NO				
2 Industry	ALL	H	NO		NO		NO				
3 Transport	ALL	H	NO		NO		NO				
4 Commercial	IE		NO		NO		NO				
5 Residential	IE		NO		NO		NO				
6 Agriculture / Forestry	NE		NO		NO		NO				
7 Territories	NE		NO		NO		NO				
B Fugitive Emissions from Fuels											
1 Solid Fuels	NE		NO		NO		NO		H	3	
2 Petroleum and Natural Gas	ALL	H	NO		NO		NO		H	3	
2 Industrial Processes											
A Mineral Products	IE		NE		NE		NE		H	3	
B Chemical Industry	ALL	H	IE		IE		IE		H	3	
C Metal Production	ALL	H	NE		ALL	M	ALL	M	M	3	
D Other Production	NA		NA		NA		NA				
E Production of Halocarbons and SF_6	NO		ALL	M	ALL	M	IE		M	2	
F Consumption of Halocarbons and SF_6	NO		ALL	M	ALL	M	ALL	M	M	2	
G Other [f]	ALL	H	NO		NO		NO		M	2	
3 Solvent and Other Product Use	ALL	H	NO		NO		NO		M	3	

NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
NA = Not applicable
PART = Partly estimated
ALL = Full estimate of all possible sources

Quality:
H = High Confidence in Estimation
M = Medium Confidence in Estimation
L = Low Confidence in Estimation

Documentation:
H = High (all background information included)
M = Medium (some background information included)
L = Low (only emission estimates included)

Disaggregation:
1 = Total emissions estimated
2 = Sectoral split
3 = Subsectoral split

[a] Non-forest soils are not included in this estimate.
[b] Estimate does not include nitrous oxide emissions from jet aircraft.
[c] Estimate excludes geologic carbon dioxide deposits released during petroleum and natural gas production.
[d] Estimate does not include emissions from industrial wastewater.
[e] Includes emissions from human sewage only
[f] From storage and transport; other industrial processes; and cooling towers, fugitive dust, and health services
[g] From landfilled wood and wood product flux
[h] From treatment, storage and disposal facilities: scrap and waste materials; and underground storage tanks

IPCC Table 8A (part IV): Overview Table for National Greenhouse Gas Inventories (1996)

Greenhouse Gas Source and Sink Categories	SO_2		HFCs		PFCs		SF_6		Documentation	Disaggregation	Footnotes
	Estimate	Quality	Estimate	Quality	Estimate	Quality	Estimate	Quality			
4 Agriculture											
A Enteric Fermentation	NE		NO		NO		NO		H	3	
B Manure Management	NE		NO		NO		NO		H	3	
C Rice Cultivation	NE		NO		NO		NO		H	3	
D Agricultural Soils	NE		NO		NO		NO		H	3	
E Prescribed Burning of Savannas	NE		NO		NO		NO				
F Field Burning of Agricultural Residues	NE		NO		NO		NO		H	3	
5 Land-Use Change & Forestry											
A Changes in Forest and Other Woody Biomass Stocks	NE		NO		NO		NO		M	2	
B Forest and Grassland Conversion	NE		NO		NO		NO				
C Abandonment of Managed Lands	NE		NO		NO		NO				
D CO_2 Emissions and Removals from Soil	NE		NO		NO		NO		M	2	
E Other [g]	NE		NO		NO		NO		M	2	
6 Waste											
A Solid Waste Disposal on Land	ALL	H	NO		NO		NO		H	3	
B Wastewater Handling	ALL	H	NO		NO		NO		H	2	
C Waste Incineration	ALL	H	NO		NO		NO		H	2	
D Other [h]	ALL	H	NO		NO		NO				
Memo Items:											
International Bunkers											
Aviation	IE		NO		NO		NO		H	1	
Marine	IE		NO		NO		NO		H	1	
CO_2 Emissions from Biomass [a]	IE		NO		NO		NO		H	2	

NE = Not estimated
IE = Estimated but included elsewhere
NO = Not known to be occurring
NA = Not applicable
PART = Partly estimated
ALL = Full estimate of all possible sources

Quality:
H = High Confidence in Estimation
M = Medium Confidence in Estimation
L = Low Confidence in Estimation

Documentation:
H = High (all background information included)
M = Medium (some background information included)
L = Low (only emission estimates included)

Disaggregation:
1 = Total emissions estimated
2 = Sectoral split
3 = Subsectoral split

[a] Non-forest soils are not included in this estimate.
[b] Estimate does not include nitrous oxide emissions from jet aircraft.
[c] Estimate excludes geologic carbon dioxide deposits released during petroleum and natural gas production.
[d] Estimate does not include emissions from industrial wastewater.
[e] Includes emissions from human sewage only
[f] From storage and transport; other industrial processes; and cooling towers, fugitive dust, and health services
[g] From landfilled wood and wood product flux
[h] From treatment, storage and disposal facilities: scrap and waste materials; and underground storage tanks

Annex O
IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion

It is possible to estimate carbon emissions from fossil fuel consumption using alternative methodologies and different data sources than those described in Annex A. For example, the IPCC requires countries in addition to their "bottom-up" sectoral methodology to complete a "top-down" Reference Approach for estimating carbon dioxide emissions from fossil fuel combustion. Section 1.3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reporting Instructions* states, "If a detailed, Sectoral Approach for energy has been used for the estimation of CO_2 from fuel combustion you are still asked to complete…the Reference Approach…for verification purposes" (IPCC/UNEP/OECD/IEA 1997). This reference method estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys. The basic principle is that once carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required. The following discussion provides the detailed calculations for estimating CO_2 emissions from fossil fuel combustion from the United States using the IPCC-recommended Reference Approach.

Step 1: Collect and Assemble Data in Proper Format

To ensure the comparability of national inventories, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention. National energy statistics were collected in physical units from several DOE/EIA documents in order to obtain the necessary data on production, imports, exports, and stock changes.[15] These data are presented in Table O-1.

The carbon content of fuel varies with the fuel's heat content. Therefore, for an accurate estimation of CO_2 emissions, fuel statistics should be provided on an energy content basis (e.g., BTU's or joules). Because detailed fuel production statistics are typically provided in physical units (as in Table O-1), they were converted to units of energy before carbon emissions can be calculated. Fuel statistics were converted to their energy equivalents by using conversion factors provided by DOE/EIA. These factors and their data sources are displayed in Table O-2. The resulting fuel data are provided in Table O-3.

Step 2: Estimate Apparent Fuel Consumption

The next step of the IPCC method is to estimate "apparent consumption" of fuels within the country. This requires a balance of primary fuels produced, plus imports, minus exports, and adjusting for stock changes. In this way, carbon enters an economy through energy production and imports (and decreases in fuel stocks) and is transferred out of the country through exports (and increases in fuel stocks). Thus, apparent consumption of primary fuels (including crude oil, natural gas liquids, anthracite, bituminous, subbituminous and lignite coal, and natural gas) can be calculated as follows:

Production + Imports - Exports - Stock Change

Flows of secondary fuels (e.g., gasoline, residual fuel, coke) should be added to primary apparent consumption. The production of secondary fuels, however, should be ignored in the calculations of apparent consumption since the carbon contained in these fuels is already accounted for in the supply of primary fuels from which they were derived

[15] For the United States, national aggregate energy statistics typically exclude data on the U.S. territories. As a result, national statistics were adjusted to include production, imports, exports, and stock changes within the United States territories. The territories include Puerto Rico, U.S. Virgin Islands, Guam, American Samoa, Wake Island, and U.S. Pacific Islands.

(e.g., the estimate for apparent consumption of crude oil already contains the carbon from which gasoline would be refined). Flows of secondary fuels should therefore be calculated as follows:

Imports - *Exports* - *Stock Change*

Note that this calculation can result in negative numbers for apparent consumption. This is a perfectly acceptable result since it merely indicates a net export or stock increase in the country of that fuel when domestic production is not considered.

The IPCC Reference Approach calls for estimating apparent fuel consumption before converting to a common energy unit. However, certain primary fuels in the United States (e.g., natural gas and steam coal) have separate conversion factors for production, imports, exports, and stock changes. In these cases, it is not appropriate to multiply apparent consumption by a single conversion factor since each of its components have different heat contents. Therefore, United States fuel statistics were converted to their heat equivalents before estimating apparent consumption. The energy value of bunker fuels was subtracted before computing energy totals.[16] Results are provided in Table O-3.

Step 3: Estimate Carbon Emissions

Once apparent consumption is estimated, the remaining calculations are virtually identical to those for the "bottom-up" Sectoral Approach (see Annex A). That is:

- Potential carbon emissions were estimated using fuel-specific carbon coefficients (see Table O-4).[17]
- The carbon sequestered in non-fuel uses of fossil fuels (e.g., plastics or asphalt) was then estimated and subtracted from the total amount of carbon (see Table O-5).
- Finally, to obtain actual carbon emissions, net carbon emissions were adjusted for any carbon that remained unoxidized as a result of incomplete combustion (e.g., carbon contained in ash or soot).[18]

Step 4: Convert to CO_2 Emissions

Because the IPCC reporting guidelines recommend that countries report greenhouse gas emissions on a full molecular weight basis, the final step in estimating CO_2 emissions from fossil fuel consumption was converting from units of carbon to units of CO_2. Actual carbon emissions were multiplied by the molecular to atomic weight ratio of CO_2 to carbon (44/12) to obtain total carbon dioxide emitted from fossil fuel combustion in teragrams (Tg). The results are contained in Table O-6.

Comparison Between Sectoral and Reference Approaches

These two alternative approaches can both produce reliable estimates that are comparable within a few percent. The major difference between methodologies employed by each approach lies in the energy data used to derive carbon emissions (i.e., the actual reported consumption for the Sectoral Approach versus apparent consumption derived for the Reference Approach). In theory, both approaches should yield identical results. In practice, however, slight discrepancies occur. For the United States, these differences are discussed below.

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[16] Bunker fuels refer to quantities of fuels used for international transportation. The IPCC methodology accounts for these fuels as part of the energy balance of the country in which they were delivered to end-users. Carbon dioxide emissions from the combustion of these fuels were estimated separately and were not included in U.S. national totals. This is done to ensure that all fuel is accounted for in the methodology and so that the IPCC is able to prepare global emission estimates.
[17] Carbon coefficients from EIA were used wherever possible. Because EIA did not provide coefficients for coal, the IPCC-recommended emission factors were used in the top-down calculations for these fuels. See notes in Table O-4 for more specific source information.
[18] For the portion of carbon that is unoxidized during coal combustion, the IPCC suggests a global average value of 2 percent. However, because combustion technologies in the United States are more efficient, the United States inventory uses one percent in its calculations for petroleum and coal and 0.5 percent for natural gas.

Differences in Total Amount of Energy Consumed

Table O-7 summarizes the differences between the two methods in estimating total energy consumption in the United States. Although theoretically the two methods should arrive at the same estimate for U.S. energy consumption, the Sectoral Approach provides an energy total that is about 2.2 percent higher than the Reference Approach. The greatest difference lies in the higher estimate of petroleum consumption with the Sectoral Approach. There are several potential sources for these discrepancies:

- *Product Definitions*. The fuel categories in the Reference Approach are different from those used in the Sectoral Approach, particularly for petroleum. For example, the Reference Approach estimates apparent consumption for crude oil. Crude oil is not typically consumed directly, but refined into other products. As a result, the United States does not focus on estimating the energy content of crude oil, but rather estimating the energy content of the various products resulting from crude oil refining. The United States does not believe that estimating apparent consumption for crude oil, and the resulting energy content of the crude oil, is the most reliable method for the United States to estimate its energy consumption. Other differences in product definitions include using sector-specific coal statistics in the Sectoral Approach (i.e., residential, commercial, industrial coking, industrial other, and transportation coal), while the Reference Approach characterizes coal by rank (i.e. anthracite, bituminous, etc.). Also, the liquefied petroleum gas (LPG) statistics used in the bottom-up calculations are actually a composite category composed of natural gas liquids (NGL) and LPG.

- *Heat Equivalents.* It can be difficult to obtain heat equivalents for certain fuel types, particularly for categories such as "crude oil" where the key statistics are derived from thousands of producers in the United States and abroad. For heat equivalents by coal rank, it was necessary to refer back to EIA's *State Energy Data Report 1992* (1994) because this information is no longer published.

- *Possible inconsistencies in U.S. Energy Data.* The United States has not focused its energy data collection efforts on obtaining the type of aggregated information used in the Reference Approach. Rather, the United States believes that its emphasis on collection of detailed energy consumption data is a more accurate methodology for the United States to obtain reliable energy data. Therefore, top-down statistics used in the Reference Approach may not be as accurately collected as bottom-up statistics applied to the Sectoral Approach.

- *Balancing Item.* The Reference Approach uses *apparent* consumption estimates while the Sectoral Approach uses *reported* consumption estimates. While these numbers should be equal, there always seems to be a slight difference that is often accounted for in energy statistics as a "balancing item."

Differences in Estimated CO_2 Emissions

Given these differences in energy consumption data, the next step for each methodology involved estimating emissions of CO_2. Table O-8 summarizes the differences between the two methods in estimated carbon emissions.

As previously shown, the Sectoral Approach resulted in a 2.2 percent higher estimate of energy consumption in the United States than the Reference Approach, but the resulting estimates of carbon emissions are almost exactly the same. While the Reference Approach estimates of coal and gas emissions were slightly higher than the bottom-up numbers, top-down oil emission estimates were lower than the Sectoral Approach. Overall emissions balance out because of these differences. Potential reasons for these patterns may include:

- *Product Definitions.* Coal data is aggregated differently in each methodology, as noted above, with United States coal data typically collected in the format used the Sectoral Approach. This results in more accurate estimates than in the Reference Approach. Also, the Reference Approach relies on a "crude oil" category for determining petroleum-related emissions. Given the many sources of crude oil in the United States, it is not an easy matter to track potential differences in carbon content between different sources of crude, particularly since information on the carbon content of crude oil is not regularly collected.

- *Carbon Coefficients.* The Reference Approach relies on several default carbon coefficients provided by IPCC (IPCC/UNEP/OECD/IEA 1997), while the Sectoral Approach uses category-specific coefficients that are likely to be more accurate. Also, as noted above, the carbon coefficient for crude oil is not an easy value to obtain given the many sources and grades of crude oil consumed in the United States.

Although the two approaches produce similar results, the United States believes that the "bottom-up" Sectoral Approach provides a more accurate assessment of CO_2 emissions at the fuel level. This improvement in accuracy is largely a result of the data collection techniques used in the United States, where there has been more emphasis on obtaining the detailed products-based information used in the Sectoral Approach than obtaining the aggregated energy flow data used in the Reference Approach. However, the United States also believes that it is valuable to understand fully the reasons for the differences between the two methods.

References

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Table O-1: 1996 U.S. Energy Statistics (physical units)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Bunkers	U.S. Territories
Solid Fuels (1000 Short Tons)	Anthracite Coal	4,768	[1]	[1]	[1]		
	Bituminous Coal	630,741	[1]	[1]	[1]		
	Sub-bituminous Coal	340,291	[1]	[1]	[1]		
	Lignite	88,056	[1]	[1]	[1]		
	Coke		1,111	1,121	21		
	Unspecified Coal		6,476	90,473	(17,411)		460
Gas Fuels (Million Cubic Feet)	Natural Gas	19,289,254	2,844,207	151,262	(11,000)		
Liquid Fuels (Thousand Barrels)	Crude Oil	2,366,017	2,747,839	40,211	(45,299)		
	Nat Gas Liquids and LRGs	669,820	77,286	19,459	(7,620)		1,450
	Other Liquids	84,349	213,934	7,869	(7)		
	Motor Gasoline		123,099	38,127	(4,287)		17,853
	Aviation Gasoline		49	-	(72)		
	Kerosene		452	793	(178)		13,967
	Jet Fuel		40,561	17,673	(146)	54,983	
	Distillate Fuel		84,234	69,603	(3,485)	18,657	22,452
	Residual Fuel		90,854	37,165	8,732	104,370	24,143
	Naptha for Petrofeed		20,231	-	(1,041)		
	Petroleum Coke		510	104,359	272		
	Other Oil for Petrofeed		52,030	-	(8)		
	Special Napthas		3,457	7,598	(139)		
	Lubricants		4,185	12,506	(291)		219
	Waxes		468	1,002	57		
	Asphalt/Road Oil		9,833	2,448	(1,997)		
	Still Gas		-	-	-		
	Misc. Products		106	84	73		13,240

[1] Included in Unspecified Coal

Data Sources: Solid Fuels - EIA Coal Industry Annual 1996; Gas Fuels - EIA Annual Energy Review 1996; Liquid Fuels - EIA Petroleum Supply Annual 1996

Table O-2: Conversion Factors to Energy Units (heat equivalents)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Bunkers	U.S. Territories
Solid Fuels (Million BTU/Short Ton)	Anthracite Coal	22.573					
	Bituminous Coal	23.89					
	Sub-bituminous Coal	17.14					
	Lignite	12.866					
	Coke		24.8	24.8	24.8		
	Unspecified		25.000	26.174	21.287		21.287
Natural Gas (BTU/Cubic Foot)		1,027	1,022	1,011	1,027		
Liquid Fuels (Million Btu/Barrel)	Crude Oil	5.800	5.935	5.800	5.800	5.800	5.800
	Nat Gas Liquids and LRGs	3.777	3.777	3.777	3.777	3.777	3.777
	Other Liquids	5.825	5.825	5.825	5.825	5.825	5.825
	Motor Gasoline		5.253	5.253	5.253	5.253	5.253
	Aviation Gasoline		5.048	5.048	5.048	5.048	5.048
	Kerosene		5.67	5.67	5.67	5.67	5.67
	Jet Fuel		5.67	5.67	5.67	5.67	5.67
	Distillate Fuel		5.825	5.825	5.825	5.825	5.825
	Residual Oil		6.287	6.287	6.287	6.287	6.287
	Naptha for Petrofeed		5.248	5.248	5.248	5.248	5.248
	Petroleum Coke		6.024	6.024	6.024	6.024	6.024
	Other Oil for Petrofeed		5.825	5.825	5.825	5.825	5.825
	Special Napthas		5.248	5.248	5.248	5.248	5.248
	Lubricants		6.065	6.065	6.065	6.065	6.065
	Waxes		5.537	5.537	5.537	5.537	5.537
	Asphalt/Road Oil		6.636	6.636	6.636	6.636	6.636
	Still Gas		6.000	6.000	6.000	6.000	6.000
	Misc. Products		5.796	5.796	5.796	5.796	5.796

Data Sources: Coal and lignite production - EIA State Energy Data Report 1992; Coke - EIA Annual Energy Review 1996; Unspecified Solid Fuels - EIA Monthly Energy Review, April 1998; Natural Gas - EIA Monthly Energy Review, April 1998; Crude Oil - EIA Monthly Energy Review, April 1998; Natural Gas Liquids and LRGs - EIA Petroleum Supply Annual 1996; all other Liquid Fuels - EIA Monthly Energy Review, April 1998

Table O-3: 1996 Apparent Consumption of Fossil Fuels (trillion Btu)

Fuel Category	Fuel Type	Production	Imports	Exports	Stock Change	Bunkers	U.S. Territories	Apparent Consumption
Solid Fuels	Anthracite Coal	107.6					-	107.6
	Bituminous Coal	15,068.4					-	15,068.4
	Sub-bituminous Coal	5,832.6					-	5,832.6
	Lignite	1,132.9					-	1,132.9
	Coke	-	27.6	27.8	0.5		-	(0.8)
	Unspecified	-	161.9	2,368.0	(370.6)		9.8	(1,825.7)
Gas Fuels	Natural Gas	19,810.1	2,906.8	152.9	(11.3)		-	22,575.2
Liquid Fuels	Crude Oil	13,722.9	16,308.4	233.2	(262.7)	-	-	30,060.8
	Nat Gas Liquids and LRGs	2,529.9	291.9	73.5	(28.8)	-	5.5	2,782.6
	Other Liquids	491.3	1,246.2	45.8	(0.0)	-	-	1,691.7
	Motor Gasoline	-	646.6	200.3	(22.5)	-	93.8	562.7
	Aviation Gasoline	-	0.2	-	(0.4)	-	-	0.6
	Kerosene	-	2.6	4.5	(1.0)	-	79.2	78.3
	Jet Fuel	-	230.0	100.2	(0.8)	311.8	-	(181.2)
	Distillate Fuel	-	490.7	405.4	(20.3)	108.7	130.8	127.6
	Residual Oil	-	571.2	233.7	54.9	656.2	151.8	(221.7)
	Naptha for Petrofeed	-	106.2	-	(5.5)	-	-	111.6
	Petroleum Coke	-	3.1	628.7	1.6	-	-	(627.2)
	Other Oil for Petrofeed	-	303.1	-	(0.0)	-	-	303.1
	Special Napthas	-	18.1	39.9	(0.7)	-	-	(21.0)
	Lubricants	-	25.4	75.8	(1.8)	-	1.3	(47.4)
	Waxes	-	2.6	5.5	0.3	-	-	(3.3)
	Asphalt/Road Oil	-	65.3	16.2	(13.3)	-	-	62.3
	Still Gas	-	-	-	-	-	-	-
	Misc. Products	-	0.6	0.5	0.4	-	76.7	76.4
Total		**58,695.8**	**23,408.3**	**4,612.1**	**(682.0)**	**1,076.6**	**548.9**	**77,646.3**

Note: Totals may not sum due to independent rounding.

Table O-4: 1996 Potential Carbon Emissions

Fuel Category	Fuel Type	Apparent Consumption (QBTU)	Carbon Coefficients (MMTCE/QBTU)	Potential Carbon Emissions (MMTCE)
Solid Fuels	Anthracite Coal	0.11	26.86	2.9
	Bituminous Coal	15.07	25.86	389.7
	Sub-bituminous Coal	5.83	26.26	153.2
	Lignite	1.13	27.66	31.3
	Coke	(0.00)	25.56	(0.0)
	Unspecified	(1.83)	25.74	(47.0)
Gas Fuels	Natural Gas	22.58	14.47	326.7
Liquid Fuels	Crude Oil	30.06	20.23	608.1
	Nat Gas Liquids and LRGs	2.78	16.99	47.3
	Other Liquids	1.69	20.23	34.2
	Motor Gasoline	0.56	19.38	10.9
	Aviation Gasoline	0.00	18.87	0.0
	Kerosene	0.08	19.72	1.5
	Jet Fuel	(0.18)	19.33	(3.5)
	Distillate Fuel	0.13	19.95	2.5
	Residual Oil	(0.22)	21.49	(4.8)
	Naptha for Petrofeed	0.11	18.14	2.0
	Petroleum Coke	(0.63)	27.85	(17.5)
	Other Oil for Petrofeed	0.30	19.95	6.0
	Special Napthas	(0.02)	19.86	(0.4)
	Lubricants	(0.05)	20.24	(1.0)
	Waxes	(0.00)	19.81	(0.1)
	Asphalt/Road Oil	0.06	20.62	1.3
	Still Gas	0.00	17.51	0.0
	Misc. Products	0.08	19.81	1.5
Total				**1545.0**

Data Sources: Coal and Lignite - *Revised 1996 IPCC Guidelines Reference Manual*, Table 1-1; Coke - EIA *Monthly Energy Review*, April 1998 Table C1; Unspecified Solid Fuels - EIA *Monthly Energy Review*, April 1998 Table C1 (U.S. Average); Natural Gas and Liquid Fuels - EIA *Emissions of Greenhouse Gases in the United States 1996.*
Note: Totals may not sum due to independent rounding.

Table O-5: 1996 Carbon Stored in Products

	Consumption for Non-Fuel Use (Trillion BTU)	(MMTCE/QBTU)	Carbon (MMTCE)	Fraction	Carbon Sequestered (MMTCE)
	27.8	25.53		0.75	0.5
	381.4	14.47		1.00	5.5
	1175.9	20.62		1.00	24.2
	1698.7	16.99		0.80	23.1
	335.5	20.24		0.50	3.4
	319.0	18.24		0.80	4.7
	[1]	[1]		[1]	13.8
	208.0	27.85		0.50	2.9
	74.5	19.86		0	0.0
	[1]	[1]		[1]	3.4
	[1]	[1]		[1]	0.2
					81.7

[1] Values for Misc. U.S. Territories Petroleum, Petrochemical Feedstocks and Waxes/Misc. are not shown because these categories are aggregates of numerous smaller components.

Table O-6: Reference Approach CO_2 Emissions from Fossil Fuel Consumption (MMTCE unless otherwise noted)

Fuel Category	Potential Carbon Emissions	Carbon Sequestered	Net Carbon Emissions	Fraction Oxidized (percent)	CO_2 Emissions (MMTCE)	CO_2 Emissions (Tg)
Coal	530.0	0.5	529.5	99.0%	524.2	1922.1
Petroleum	688.3	75.7	612.7	99.0%	606.5	2223.9
Natural Gas	326.7	5.5	321.1	99.5%	319.5	1171.6
Total	**1,545.0**	**81.7**	**1463.3**	**-**	**1450.3**	**5317.7**

Note: Totals may not sum due to independent rounding.

Table O-7: 1996 Energy Consumption in the United States: Sectoral vs. Reference Approaches (trillion BTU)

Approach	Coal	Natural Gas	Petroleum	Total
Sectoral[a]	20,570	22,508	36,340	79,419
Reference (Apparent)[a]	20,315	22,575	34,756	77,646
Difference	**-1.2%**	**0.3%**	**-4.4%**	**-2.2%**

[a] Includes U.S. territories

Note: Totals may not sum due to independent rounding.

Table O-8: 1996 CO_2 Emissions from Fossil Fuel Combustion by Estimating Approach (MMTCE)

Approach	Coal	Natural Gas	Petroleum	Total
Sectoral[a]	524.0	318.6	607.7	1450.3
Reference[a]	524.2	319.5	606.5	1450.3
Difference	**0.0%**	**0.3%**	**-0.2%**	**0.0%**

[a] Includes U.S. territories

Note: Totals may not sum due to independent rounding.

Annex P
Preliminary 1997 Estimates of U.S. Greenhouse Gas Emissions and Sinks

This annex provides preliminary 1997 estimates of greenhouse gas emissions and sinks. Although these calculations are not final, large changes are not expected, and therefore, this annex allows the reader to evaluate the trend in U.S. emissions.

The following trends are evident based on a comparison of these preliminary 1997 estimates and 1990 through 1996 estimates found in the body of this report. In 1997, total U.S. emissions appear to have grown by 180 MMTCE (11.0 percent) since 1990. From 1996 to 1997, emissions rose by 1.4 percent, or 25 MMTCE. Table P-1 below shows preliminary estimates in teragrams (Tg) of gas and MMTCE.

Specifically, emissions of CO_2 increased by 10.6 percent over the 8 year period, and by 1.4 percent in the last year. Increases in emissions from coal and natural gas combustion by utilities and petroleum consumption by industry were responsible for the majority of this increase in emissions.

Methane emissions grew by 5.5 percent over the 1990 to 1997 period, and by 0.4 percent in the last year. From 1996 to 1997, most CH_4 sources experienced small increases or decreases. Emissions from rice cultivation grew the most in terms of percentage (10.1 percent), while landfill emissions grew the most absolutely (1.6 MMTCE).

Nitrous oxide emissions rose 13.8 percent over the 1990 to 1997 period. However, from 1996 to 1997, N_2O emissions increased by only 1.2 percent or 1.3 MMTCE. In the last year, emissions from adipic acid production dropped by 37 percent due to improved industrial controls. As a percentage increase, emissions from manure management rose the most (25.7 percent). The source contributing the most to the total N_2O increase was agricultural soil management (1.6 MMTCE).

Emissions of HFCs, PFCs, and SF_6 showed a 6.4 percent increase from 1996 to 1997. Over the 1990 to 1997 period, emissions from this sector increased by 66.4 percent or 14.7 MMTCE. In the last year, emissions from HCFC-22 production and semiconductor manufacture showed a slight decrease. However, increased emissions of 2.6 MMTCE from the substitution of ozone depleting substances offset this trend.

Table P-1: Preliminary 1997 Estimates of U.S. Greenhouse Gas Emissions and Sinks

Gas/Source	Tg	MMTCE
CO_2	**5,469.3**	**1,491.6**
Fossil Fuel Combustion	5,391.4	1,470.4
Natural Gas Flaring	12.4	3.4
Cement Manufacture	38.8	10.6
Lime Manufacture	14.2	3.9
Limestone and Dolomite Use	7.0	1.9
Soda Ash Manufacture and Consumption	4.4	1.2
Carbon Dioxide Manufacture	1.1	0.3
Land-Use Change and Forestry (Sink)[a]	(764.7)	(208.6)
CH_4	**31.3**	**179.3**
Stationary Sources	0.39	2.24
Mobile Sources	0.2	1.2
Coal Mining	3.3	18.7
Natural Gas Systems	5.9	33.5
Petroleum Systems	0.3	1.6
Petrochemical Production	0.1	0.4
Silicon Carbide Production	+	+
Enteric Fermentation	6.0	34.2
Manure Management	3.0	17.0
Rice Cultivation	0.5	2.7
Agricultural Residue Burning	+	0.2
Landfills	11.7	66.7
Wastewater Treatment	0.2	0.9
N_2O	**876.7**	**105.0**
Stationary Sources	+	4.13
Mobile Sources	0.2	16.9
Adipic Acid	+	3.4
Nitric Acid	0.1	4.2
Manure Management	43.9	3.7
Agricultural Soil Management	830.8	70.2
Agricultural Residue Burning	1.6	0.1
Human Sewage	+	2.3
Waste Combustion	+	0.1
HFCs, PFCs, and SF_6	**M**	**36.9**
Substitution of Ozone Depleting Substances	M	14.5
Aluminum Production	M	2.9
HCFC-22 Production[b]	+	8.2
Semiconductor Manufacture	M	1.3
Electrical Transmission and Distribution[c]	+	7.0
Magnesium Production and Processing[c]	+	3.0
Total Emissions	**NA**	**1812.9**
Net Emissions	**NA**	**1604.4**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 Tg or 0.05 MMTCE
M (Mixture of multiple gases)
NA (Not Applicable)
[a] Sinks are not included in CO_2 emissions total.
[b] HFC-23 emitted
[c] SF_6 emitted

Annex Q
Sources of Greenhouse Gas Emissions Excluded

Although this report is intended to be a comprehensive assessment of anthropogenic sources and sinks of greenhouse gas emissions for the United States, certain sources have been identified yet excluded from the estimates presented for various reasons. Before discussing these sources, however, it is important to note that processes or activities that are not *anthropogenic in origin* or do not result in a *net source or sink* of greenhouse gas emissions are intentionally excluded from a national inventory of greenhouse gas emissions. In general, processes or activities that are not anthropogenic are considered natural (i.e., not directly influenced by human activity) in origin and, as an example, would include the following:

- Volcanic eruptions
- CO_2 exchange (i.e., uptake or release) by oceans
- Natural forest fires[19]
- CH_4 emissions from wetlands not affected by human induced land-use changes

Some activities or process may be anthropogenic in origin but do not result in net emissions of greenhouse gases, such as the respiration of CO_2 by living organisms. Given a source category that is both anthropogenic and results in net greenhouse gas emissions, reasons for excluding a source related to an anthropogenic activity include one or more of the following:

- There is currently insufficient scientific understanding to develop a reliable method for estimating emissions at a national level.
- Although an estimating method has been developed, data was not adequately available to calculate emissions.
- Emissions were implicitly accounted for within another source category (e.g., CO_2 from fossil fuel combustion).

It is also important to note that the United States believes the exclusion of the sources discussed below introduces only a minor bias in its overall estimate of U.S. greenhouse gas emissions.

N_2O from the Combustion of Jet Fuel

The combustion of jet fuel by aircraft results in N_2O emissions. The N_2O emissions per mass of fuel combusted during landing/take-off (LTO) operations differ significantly from those during aircraft cruising. Accurate estimation of these N_2O emissions requires a detailed accounting of LTO cycles and fuel consumption during cruising by aircraft model (e.g., Boeing 747-400). Sufficient data for calculating such N_2O emissions were not available for this report. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, pp. 1.93 - 1.96)

Emissions from Bunker Fuels and Fossil Fuels Combusted Abroad by the U.S. Military

Emissions from fossil fuels combusted in military vehicles (i.e., ships, aircraft, and ground vehicles) may or may not be included in U.S. energy statistics. Domestic fuel sales to the military are captured in U.S. energy statistics; however, fuels purchased abroad for base operations and refueling of vehicles are not. It is not clear to what degree fuels purchased domestically are exported by the military to bases abroad.

[19] In some cases forest fires that are started either intentionally or unintentionally are viewed as mimicking natural burning processes which have been suppressed by other human forest management activities. The United States does not consider forest fires within its national boundaries to be a net source of greenhouse emissions.

Fuels combusted by military ships and aircraft while engaged in international transport or operations in international waters or airspace (i.e., flying or cruising in international airspace or waters) that is purchased domestically is included in U.S. energy statistics. Therefore, the United States currently under reports its emissions of CO_2 from international bunker fuels, and most likely over reports its CO_2 emissions from transportation related fossil fuel combustion by the same amount. At this time, fuel consumption statistics from the Department of Defense are not adequately detailed to correct for this bias.[20]

CO_2 from Burning in Coal Deposits and Waste Piles

Coal is periodically burned in deposits and waste piles. It has been estimated that the burning of coal in deposits and waste piles would represent less than 1.3 percent of total U.S. coal consumption (averaged over ten-years). Because there is currently no known source of data on the quantity of coal burned in waste piles and there is uncertainty as to the fraction of coal which is oxidized during such burnings, these CO_2 emissions are not currently estimated. Further research would be required to develop accurate emission factors and activity data for these emissions to be estimated. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 1.112 - 1.113)

Fossil CO_2 from Petroleum and Natural Gas Wells, CO_2 Separated from Natural Gas, and CO_2 from Enhanced Oil Recovery (EOR)

Petroleum and natural gas well drilling, petroleum and natural gas production, and natural gas processing—including removal of CO_2—may result in emissions of CO_2 that was at one time stored in underground formations. Sufficient methodologies for estimating emissions of this "fossil" CO_2 at the national level have not been adequately developed.

Carbon dioxide is also injected into underground deposits to increase crude oil reservoir pressure in a field technique known as enhanced oil recovery (EOR). It is thought that much of the injected CO_2 may be effectively and permanently sequestered, but the fraction of injected CO_2 which is re-released remains uncertain. The fraction re-released varies from well to well depending upon the field geology and the gas capture/re-injection technology employed at the wellhead. Further research into EOR is required before the resulting CO_2 emissions can be adequately quantified. (see the discussion of the Carbon Dioxide Manufacture source category in the Industrial Processes sector)

Carbon Sequestration in Underground Injection Wells

Organic hazardous wastes are injected into underground wells. Depending on the source of these organic substances (e.g., derived from fossil fuels) the carbon in them may or may not be included in U.S. CO_2 emission estimates. Sequestration of carbon containing substances in underground injection wells may be an unidentified sink. Further research is required to if this potential sink is to be quantified.

CH_4 from Abandoned Coal Mines

Abandoned coal mines are a source of CH_4 emissions. In general, many of the same factors that affect emissions from operating coal mines will affect emissions from abandoned mines such as the permeability and gassiness of the coal, the mine's depth, geologic characteristics, and whether it has been flooded. A few gas developers have recovered methane from abandoned mine workings; therefore, emissions from this source may not be insignificant. Further research and methodological development is needed if these emissions are to be estimated.

CO_2 from Unaccounted for Natural Gas

There is a discrepancy between the amount of natural gas sold by producers and that reported as purchased by consumers. This discrepancy, known as unaccounted for or unmetered natural gas, was assumed to be the sum of

[20] See the Defense Energy Support Center (formerly the Defense Fuel Supply Center), *Fact Book 1997*. [http://www.desc.dla.mil/main/pulicati.htm]

leakage, measurement errors, data collection problems, undetected non-reporting, undetected overreporting, and undetected underreporting. Historically, the amount of gas sold by producers has always exceeded that reportedly purchased by consumers; therefore, some portion of unaccounted for natural gas was assumed to be a source of CO_2 emissions. (It was assumed that consumers were underreporting their usage of natural gas.) In DOE/EIA's energy statistics for 1996, however, reported consumption of natural gas exceeded the amount sold by producers. Therefore, the historical explanation given for this discrepancy has lost credibility and unaccounted for natural gas is no longer used to calculate CO_2 emissions. (see section on Changes in the U.S. Greenhouse Gas Inventory Report)

CO_2 from Shale Oil Production

Oil shale is shale saturated with kerogen.[21] It can be thought of as the geological predecessor to crude oil. Carbon dioxide is released as a by-product of the process of producing petroleum products from shale oil. As of now, it is not cost-effective to mine and process shale oil into usable petroleum products. The only identified large-scale oil shale processing facility in the U.S. was operated by Unocal during the year of 1985 to 1990. There have been no known emissions from shale oil processing in the United States since 1990 when the Unocal facility closed.

CH_4 from the Production of Carbides other than Silicon Carbide

Methane may be emitted from the production of carbides because the petroleum coke used in the process contains volatile organic compounds which form methane during thermal decomposition. Methane emissions from the production of silicon carbide were estimated and accounted for, but emissions from the production of calcium carbide and other carbides were not. Further research is needed to estimate CH_4 emissions from the production of calcium carbide and other carbides other than silicon carbide. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, pp. 2.20 - 2.21)

CO_2 from Calcium Carbide and Silicon Carbide Production

Carbon dioxide is formed by the oxidation of petroleum coke in the production of both calcium carbide and silicon carbide. These CO_2 emissions are implicitly accounted for with emissions from the combustion of petroleum coke under the Energy sector. There is currently not sufficient data on coke consumption to estimate emissions from these sources explicitly. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, pp. 2.20 - 2.21)

CO_2 from Graphite Consumption in Ferroalloy and Steel Production

The CO_2 emissions from the three reducing agents used in ferroalloy and steel production—coke, wood (or biomass), and graphite—are accounted for as follows:

- Emissions resulting from the use of coke are accounted for in the Energy sector under fossil fuel combustion.
- Estimating emissions from the use of wood or other biomass materials is unnecessary because these emissions should be accounted for under Land-Use Change and Forestry sector if the biomass is harvested on an unsustainable basis.
- The CO_2 emissions from the use of graphite, which is produced from petroleum by-products, may be accounted for in the Energy sector (further analysis is required to determine if these emissions are being properly estimated). The CO_2 emissions from the use of natural graphite, however, have not been accounted for in the estimate.

Emissions from graphite electrode consumption—versus its use as a reducing agent—in ferroalloy and steel production may at present only be accounted for in part under fossil fuel combustion if the graphite used was derived from a fossil fuel substrate (versus natural graphite ore). Further research into the source and total consumption of

[21] Kerogen is fossilized insoluble organic material found in sedimentary rocks, usually shales, which can be converted to petroleum products by distillation.

graphite for these purposes is required to explicitly estimate emissions. (see Iron and Steel Production and Ferroalloy Production in the Industrial Processes sector)

N_2O from Caprolactam Production

Caprolactam is a widely used chemical intermediate, primarily to produce nylon-6. All processes for producing caprolactam involve the catalytic oxidation of ammonia, with N_2O being produced as a by-product. Caprolactam production could be a significant source of N_2O—it has been identified as such in the Netherlands. More research is required to determine this source's significance because there is currently insufficient information available on caprolactam production to estimate emissions in the United States. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, pp. 2.22 - 2.23)

N_2O from Cracking of Certain Oil Fractions

In order to improve the gasoline yield in crude oil refining, certain oil fractions are processed in a catcracker. Because crude oil contains some nitrogen, N_2O emissions may result from this cracking process. There is currently insufficient data to develop a methodology for estimating these emissions. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.23)

CH_4 from Coke Production

Coke production may result in CH_4 emissions. Detailed coke production statistics were not available for the purposes of estimating CH_4 emissions from this minor source. (see Petrochemical Production under the Industrial Processes sector and the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.23)

CO_2 from Metal Production

Coke is used as a reducing agent in the production of some metals from their ores, including magnesium, chromium, lead, nickel, silicon, tin, titanium, and zinc. Carbon dioxide may be emitted during the metal's production from the oxidization of the coke used as a reducing agent and, in some cases, from the carbonate ores themselves (e.g., some magnesium ores contain carbonate). The CO_2 emissions from coke oxidation are accounted for in the Energy sector under Fossil Fuel Combustion. The CO_2 emissions from the carbonate ores are not presently accounted for, but their quantities are thought to be minor. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.37 - 2.38)

N_2O from Acrylonitrile Production

Nitrous oxide may be emitted during acrylonitrile production. No methodology was available for estimating these emissions, and therefore further research is needed if these emissions are to be included. (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.22)

Miscellaneous SF_6 Uses

Sulfur hexafluoride may be used in gas-filled athletic shoes, in foam insulation, for dry etching, in laser systems, as an atmospheric tracer gas, for indoor air quality testing, for laboratory hood testing, for chromatography, in tandem accelerators, in sound-insulating windows, in tennis balls, in loudspeakers, in shock absorbers, and for certain biomedical applications. Data need to be gathered and methodologies developed if these emissions are to be estimated.

CO_2 from Solvent Incineration

CO_2 may be released during the incineration of solvents. Although emissions from this source are believed to be minor, data need to be gathered and methodologies developed if these emissions are to be estimated.

CO_2 from Non-Forest Soils

Non-forest soils emit CO_2 from decaying organic matter and carbonate minerals—the latter may be naturally present or mined and later applied to soils as a means to adjust their acidity. Soil conditions, climate, and land-use practices interact to affect the CO_2 emission rates from non-forest soils. The U.S. Forest Service has developed a model to estimate CO_2 emissions from forest soils, but no such model has been adequately developed for non-forest soils. Further research and methodological development is needed if these emissions are to be accurately estimated. (see Changes in Non-Forest Carbon Stocks under the Land-Use Change and Forestry sector)

CH_4 from Land-Use Changes Including Wetlands Creation or Destruction

Wetlands are a known source of CH_4 emissions. When wetlands are destroyed, CH_4 emissions may be reduced. Conversely, when wetlands are created (e.g., during the construction of hydroelectric plants), CH_4 emissions may increase. Grasslands and forest lands may also be weak sinks for CH_4 due to the presence of methanotrophic bacteria that use CH_4 as an energy source (i.e., they oxidize CH_4 to CO_2). Currently, an adequate scientific basis for estimating these emissions and sinks does not exist, and therefore further research and methodological development is required.

CH_4 from Septic Tanks and Drainfields

Methane is produced during the biodegradation of organics in septic tanks if other suitable electron-acceptors (i.e., oxygen, nitrate, or sulfate) besides CO_2 are unavailable. Such conditions are called methanogenic. There were insufficient data and methodological developments available to estimate emissions from this source.

N_2O from Wastewater Treatment

As a result of nitrification and denitrification processes, N_2O may be produced and emitted from wastewater treatment plants. Nitrogen-containing compounds are found in wastewater due to the presence of both human excrement and other nitrogen-containing constituents (e.g. garbage, industrial wastes, dead animals, etc.). The portion of emitted N_2O which originates from human excrement is currently estimated under the Human Sewage source category—based upon average dietary assumptions. The portion of emitted N_2O which originates from other nitrogen-containing constituents is not currently estimated. Further research and methodological development is needed if these emissions are to be accurately estimated.

CH_4 from Industrial Wastewater

Methane may be produced during the biodegradation of organics in wastewater treatment if other suitable electron-acceptors (i.e. oxygen, nitrate, or sulfate) besides CO_2 are unavailable. Such conditions are called methanogenic. Methane produced from domestic wastewater treatment plants is accounted for under the Waste sector. These emissions are estimated by assuming an average 5-day biological oxygen demand (BOD_5) per capita contribution in conjunction with the approximation that 15 percent of wastewater's BOD_5 is removed under methanogenic conditions. This method itself needs refinement. It is not clear if industrial wastewater sent to domestic wastewater treatment plants, which may contain biodegradable material, would be accounted for in the average BOD_5 per capita number. Additionally, CH_4 emissions from methanogenic processes at industrial wastewater treatment plants are not currently estimated. Further research and methodological development is needed if these emissions are to be accurately estimated. (see Wastewater Treatment under the Waste sector)